DOCUMENT HOLDER & UPDATES

This document is an uncontrolled copy of the ADCO Drilling Manual “ADM”. It was originally issued to the following position.

| Holder Name | __________________________ |
| Holder Position | __________________________ |

The electronic copy of the ADCO Drilling Manual is the only controlled copy that contains the most updated version. It is on PDF format, available on the Drilling Division Website and can be accessed through the ADCO Intranet.

Only the electronic copy on the web will be updated on which notification will be given to Drilling staff via e-mail.
MANUAL APPROVAL SHEET

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OWNER / HOLDER AND CUSTODIAN

The Owner / Holder of the ADCO Drilling Manual (ADM) is responsible for approving the appropriate programs to ensure awareness and proper use of the ADM. The ADM Owner / Holder’s responsibilities also include the following maintenance activities:

- The review and approval of the manual as being technically and operationally correct.
- The management of timely reviews and revisions to the manual.
- Participation in auditing and reviewing of the manual.

Owner / Holder

Abdullah S. Al-Suwaidi – Drilling Manager

Date: _________________

The Custodian of the manual is nominated by the Owner / Holder and is responsible for the contents of the ADM. He is responsible for ensuring that revisions and updates are prepared when necessary. The Custodian is also responsible for ensuring that the distribution of the ADM and its corrections and revisions are adequately controlled.

Custodians

Medhat Al Habsi – Head of Drilling Operations (SAS/NEB/EXPL)

Date: _________________

David Morgan – Head of Drilling Operations (BUH / BAB)

Date: _________________

Enquiries as to the content of the ADM should be addressed to the Custodian.
Following is the first issue of Volume -1 “Drilling Operations” of the ADCO Drilling Manual “ADM”, which has been developed to replace the Standard Drilling Instruction (SDI) document. The Manual is intended to be a distillation of ADCO’s experience contained in documents such as Drilling Safety Manual, H₂S Manual, Well Cost Manual and others, which are all now obsolete.

This volume of the ADM comprises of the following chapters:

Chapter-1 Policies
Chapter-2 Drilling Operations Guidelines
Chapter-3 Well Control
Chapter-4 Drilling Optimization
Chapter-5 Mud Guidelines
Chapter-6 Casing and Cementing

To maintain the Manual’s usefulness in relation to current developing technologies and accumulating operational experience, frequent updating is essential. Feedback in the form of constructive suggestions, both verbal and in writing, is encouraged and should be addressed to the HDO (S/N/E) and HDO(Bu/Bb), who are the custodians of this manual, or to the Drilling Team Leader Studies. The suggestions will be reviewed and if accepted will be incorporated in the relative chapter.

Abdullah S. Al-Suwaidi
DRILLING MANAGER
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MANUAL INTERFACES WITH OTHER ADCO’S MANUALS

There are other manuals within the ADCO’s management system that have to be considered when planning and designing wells and during the operational phase. These other manuals are listed below:

- Health, Safety and Environment Management System (HSEMS)
- Emergency Response Documentation (Procedure Manual 10/2)
- Coiled Tubing Manual
- Drilling HSE Plan
- Wellbore Positioning Manual (WPM)
- Blowout Contingency Plan (BOCP)
- Materials Standards for Drilling Equipment
- Generic Well Program (GWP)
- Drilling Program

All Drilling personnel must make themselves familiar with ALL of the above manuals / documents and ensure that drilling programs do not conflict with them.

There are three basic levels of manuals that are related to drilling management and operations. The positions of these manuals are outlined below:
RESPONSIBILITIES

Drilling Manager

The DM is responsible for the overall operations management, he
- Approves the content of the manual.
- Ensures Drilling Staff is trained and aware of how to use the manual.
- Approves dispensations from the policies and guidelines set in the manual (can delegate this responsibility to HDO).
- Makes changes to how the management of the manual is undertaken.

Head of Drilling Operations (HDO)

- Reviews and endorses the content of the manual.
- Responsible for the implementation of the contents of the manual.
- Communicates with other divisions in regard to the manual content.
- Endorses and approves dispensations from the policies and guidelines set out in the manual if delegated by DM.

Head of Technical (Drilling)

- Reviews the content of the manual and approves what related to his duty as Head of Technical.
- Communicates with PDD when required on all technical aspects contained in the manual.
- Proposes updates to the manual on the basis of actual experience and lessons learned related to well equipment, quality and integrity.

Head of Planning & Systems (Drilling)

- Responsible of the content of the manual that related to his duty as Head of Planning & Systems.
- HPS(D) shall propose updates to the contents related to Drilling Planning, Systems, Administration, and Cost Control.

Drilling Team Leader (Studies)

- Acts as custodian of the Drilling Division Manuals, responsible of maintaining the manual fit for purpose.
- Fully responsible of the technical content update of the manual.
- Ensures that all approved “Requests for Change”, comments and lessons learned are incorporated in the manual.
• Keeps proper records for the revisions and updates.
• Ensures that the distribution of the ADM and its corrections and revisions are adequately managed.

**Drilling Team Leader (DTL)/Senior Operations Engineer (SOE)**

• Ensure the wells are designed and the operations are undertaken according to the policies and guidelines set in the manual.
• No dispensations to proceed without the DM or HDO authorization.
• Continuously propose updates to the manual on the basis of actual experience and lessons learned to keep it fit for purpose.

**Rig site Drilling Supervisor and Drilling Engineer**

• Ensure that the detailed drilling program is not in conflict with the policies, procedures and guidelines stated in this manual.
• Ensured that all operations are carried out in accordance with this manual.
• Proposes updates to the manual on the basis of actual experience and lessons learned.

**DISPENSATION AND REGULATORY REQUIREMENTS**

It is ADCO’s policy to carry out all operations in compliance with current laws and regulations in force in Abu Dhabi. To that end this manual should be regularly checked for compliance with current regulatory requirements, and should be amended immediately if compliance does not exist.

In the event of a conflict between this manual and any Government Law or Regulation the Law or Regulations shall take precedence.

In such cases the conflict shall be notified to the Holder (DM) and Custodian (HDO) of this Manual. The Custodian shall take immediate action to rectify any such conflict by amending this Manual as necessary. Particular note should be taken of Law 8, which relates to oil and gas exploitation.

It is recognized that in exceptional circumstances it may be necessary to deviate or dispense from the prescriptions of this Manual, this dispensations must be controlled, sought and approved in writing, and a record kept in the relevant well file, Studies to advise HDO’s of the dispensations records.

Different levels of approval are required for deviations from the Manual. These are outlined as follows:

• For deviations from Chapter-1 (Policies) of Volume-1, the approval of the Drilling Manager must be obtained.
• For deviations from any chapter in any volume of this manual (except Chapter-1, Volume-1). The approval of the Head of Drilling Operations must be obtained.

All requests for dispensation, and deviation from this manual, shall provide the technical reasons for the requested change, and must include a description of any proposed new procedure. Additionally, all requests for dispensation shall state the impact on safety and costs.

ELECTRONIC STATUS, LOCATION, ISSUING, UPDATING & REVISION

This manual is distributed for use in paper copies and in electronic format.

The Custodian will hold the MASTER COPY in Word format. This is the document from which the electronic versions for distribution are generated. It is the Custodian’s responsibility to ensure that no unauthorized modifications are made to the Manual. To ensure this security is maintained, the electronic Master Copies of the manual must be password protected and should be only available to the Custodian, DTL (Studies) and a limited number of other authorized personnel.

To ensure this Manual is updated and revised as necessary the Custodian shall maintain a record of all suggestions put forward for amendments to the Manual. The Custodian shall also carry out regular half yearly reviews of the manual to determine the need for revision.
## DISPENSATION FORM

### Abu Dhabi Company for Onshore Oil Operations

#### DISPENSATION FROM POLICY AND/OR CHANGE TO PROGRAMME

1. **Dispensation from what?** Tick boxes as required
   - Policy
   - Practices
   - Material standard

   **Well Name:**

   **Rig Name:**

2. **Relevant Policy / Programme Section**
   - **Volume No. / Title:**
   - **Chapter No. / Title:**
   - **Section No. / Title:**
   - **Topic:**

3. **Dispensation / Change Required**

4. **Justification**

5. **Safety Implication**

6. **Cost Impact**

7. **Comments**

8. **Signatures**

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Printed on: 02/03/2005
MANUAL REVISION RECORD

Since the manual's electronic copy is the only controlled copy that contains the latest update of each chapter, the print date of that particular chapter will be shown at the footer of each page.

When any chapter is revised or updated, the update is given a sequential number showing the revision number and the year “Rev-N/year”. The revisions will be limited to chapters only.

The page number shown at the end of each page footer is the sequential number within each chapter (e.g. first page of Chapter-2 is “2-1”). The same principle is applied to the Figures and Tables' numbers in each chapter.

The following update record sheet shall be completed upon receiving any revision.

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Drilling Division

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MANUAL DISTRIBUTION LIST

The Manual is issued to the present holder of the post for use by that person for the duration of his/her incumbency only; upon leaving the post the manual shall be left for a replacement.

- One CD is attached to each paper hard copy.
- The manual is posted on the Drilling web site.
- The document on the CD and Drilling web site is a PDF file version.
- The copy posted on the Drilling web site shall always take precedence over copies distributed in other media.

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<td>DS</td>
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POLICIES

Revision-0
March 2005
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SECTION 1

GENERAL

1. Policy Statement

The Policies contained in this document are mandatory and are the fundamental standards that are to be employed in all areas of the ADCO Drilling Operations.

2. Implementation

All ADCO staff personnel engaged in managing ADCO Well Operations must be fully conversant with these policies, and they are responsible for their compliance.

3. Dispensations and Deviations from Policy

For dispensation from this chapter “Policies”, the approval of the Drilling Manager (DM) must be obtained.

4. Roles and Responsibilities

Clear roles, responsibilities and accountabilities must be established for all positions within the Drilling Division organization.

5. Competency

- Competency of staff to undertake key roles within ADCO’s Drilling Division must be regularly assessed and enhanced.
- All new employees, transferees, must be given an induction course and a safety orientation upon reporting to work.
- All ADCO personnel working in Drilling Operations must be fully conversant with the ADCO Emergency Response Documentation Manual and the Blowout Contingency Plan Manual.

6. Security

- All personnel (ADCO and Contractors) working in the ADCO fields must possess a valid government security pass.
• All new arrivals to the rig must report immediately to the rig Health & Administrator Officer (HAO) and will be briefed on safety polices and contingency procedure.

• Rig medic must maintain all times an updated list of personnel on rigsite, the records must include:
  o Full Name.
  o Work discipline
  o Date and time of arrival/departure

7. Transportation / Road Safety

• All vehicles working in ADCO fields must posses a valid government security pass and have a VMS system installed.

• ADCO and Contractor employees, who are required to drive as part of their job, must hold a valid UAE driving license and ADCO DSD (Defensive Driving).

• Driving at night either in the desert, on the black top, on the gatch road, or on the sand track is prohibited except in emergency cases or for essential operations reasons, at discretion of DTL and HDO.

• Journey Management Systems requires all drivers to give their journey details to the relevant control room. They must book out when they depart and book in when they log in arrival destination security gate.

• All issues related to transportation and road safety must be referred to ADCO Procedure Manual 10/3.
SECTION 2

CLASSIFICATION OF DRILLING RISK

Some policies will vary with the degree of risk associated with each drilling operation. To apply the relevant policies to the intended operation, wells are classified in accordance with the following risk categories:

Category (A) : High Risk Wells
Category (B) : Medium Risk Wells
Category (C) : Low Risk Wells

Table 1-1: Wells classification according to risk category

| Category (A) High Risk Wells | 1) All Gas wells.  
| 2) All Exploration wells.  
| 3) Oil wells of H₂S content of 10,000 PPM or more.  
| 4) Oil wells with an anticipated SIWHP of 3000 psi or more (calculated based on expected formation pressure and formation fluid column).  
| 5) Oil wells located within 1000 meter or less of a populated area or public highway.  
| 6) Wells requiring workover in which integrity is suspect, i.e. wells with sustainable annulus pressure into 9 ⅜” casing and / or 13 ⅜” csg.  |

| Category (B) Medium Risk Wells | 1) Oil wells, drilling or workover, capable of sustaining natural flow to surface.  
| 2) Oil wells with anticipated SIWHP of less than 3000 psi (calculated based on expected formation pressure and formation fluid column).  
| 3) Oil wells contain H₂S <10,000 PPM.  |

| Category (C) Low Risk Wells | 1) Wells of any type that are not capable of sustaining natural flow to surface.  
| 2) Any well not covered by categories (A) and (B).  
| 3) Water Supply and Water Disposal wells.  |
SECTION 3

SAFETY AND OCCUPATIONAL HEALTH

1. Corporate Policy on Health, Safety and Environment (HSE)

It is the policy of the Abu Dhabi Company for Onshore Oil Operations (ADCO) to conduct its activities in such a way as to:

- Take foremost account of the health and safety of its employees and contractors;
- Give proper regard to the conservation of the environment, and;
- Impact to local communities.

The company will make continuous effort to prevent all accidents, injuries and occupational illness and to reduce environmental impacts and damage to assets, through the active participation of every employee and contractor.

The company believes that good HSE performance is an integral part of its business and will treat HSE issues equal to other primary business objectives.

ADCO will, through the documented Health, Safety and Environment Management System (HSEMS), implement this policy.

2. Corporate Strategy to Achieve the HSE Policy

2.1 On General HSE Aspects

- Comply with or exceed all applicable laws and regulations and apply internationally recognized standards where local laws and regulations do not exist.
- Hold all levels of management and staff accountable for HSE issues and for the development of positive attitudes in themselves and those they supervise.
- As a minimum requirement contractors to apply HSE standards and practices compatible to ADCO's.
- Provide appropriate HSE training to employees and contractors.
- Design facilities, establish practices and conduct operations in a manner that minimizes risks and hazards.
- Set realistic and measurable HSE targets.
• Undertake appropriate reviews and evaluations to measure HSE performance against identified targets, standards and to ensure compliance with ADCO's policy.

• Openly report HSE performance (good and bad).

• Develop and maintain HSE emergency procedures in co-operation, where necessary, with other operating companies, the local authorities and emergency services.

2.2 On Health

• Control and manage all chemical, physical, biological and mechanical factors which contribute to health risks, based on established guidelines and standards,

• Promote the health of employees, both company and contractors.

2.3 On Safety

• Ensure all operations are conducted with the safety of the employee and community as a main objective.

• Hold all levels of ADCO and Contractors management and staff line accountable for the implementation of ADCO’s Road Safety Strategy.

2.4 On Environment

• Strive to progressively reduce emissions, discharges and wastes.

• Preserve and protect sites of archaeological and historical interest in its areas of operation.

• Continuously improve the efficient use of energy and natural resources.

3. Safety Priorities

Priorities for safety when planning and undertaking drilling and well operations must be, in order of importance: 1) personnel, 2) environment, 3) Assets.

4. HSE Policy Manuals

There are three primary references for ADCO HSE policies. For a complete review of HSE Policy, it is recommended to refer to:
1) ADCO HSE Management System (HSEMS)
2) Procedure Manual Volume 10 (HSE)
3) Procedure Manual 10/3, Transportation and Road Safety

5. **Simultaneous Operations (SIMOPS)**

- Before moving any rig to an existing cluster, drilling supervisor to identify the type of the nearby production wells and the distance between these wells and the well to be drilled or worked-over within the subject existing cluster.

- Based on the type of the nearby production wells (gas, oil or water well), and the distance, the appropriate Risk Reduction Measure that is applicable to each individual activity must be selected.
SECTION 4

DRILLING WASTE MANAGEMENT POLICY

1. General

- Continuously ensure that drilling operations have As Low As Reasonably Practical (ALARP) impact on the environment.

- Continuously strive to reduce the volume and toxicity of waste generated.

- Ensure Zero surface discharge in sensitive areas.

- Encourage attitude of performance with the compliance or Environmental Regulations and Guidelines.

- Encourage reuse of drilling fluid and other waste.

- Disposed effluents and solids must meet ADNOC (COP) environmental specifications.

2. Un-Allowable Surface Disposal

- Oil based mud, emulsion liquids and oily cuttings.

- Aquifer water and brines.

- All liquids in Sabkha, islands and Dabbiya area.

- Water based cuttings in sensitive areas.

- Crude oil, acid and water produced during testing.

- Rig and camp trash including used parts.

- Untreated sewage.

- Crude oil flaring.

- Gas flaring.

Note: In case of emergencies, flaring may be conducted without ADNOC approval. However, ADCO management must be informed in advance if possible.
3. **Allowable Surface Disposal**

- Water based cuttings in non-sensitive areas.
- Treated sewage water.
- Liquids with salinity $<16,000$ ppm chloride except in Sabkha, islands and Dhabbiya area.
- Any deviation, from all above, requires advanced management approval. Oil and Gas flaring requires ADNOC approval and as such forward planning for handling hydrocarbons must be followed.
SECTION 5

WELL PLANNING

- All wells must be designed to contain well fluids to surface and provide hydrocarbon zonal isolation to prevent the cross flow of hydrocarbons from one reservoir unit to another or to the aquifer.

- All drilling operations of category (A) wells must be risk assessed. Appropriate operating and emergency procedures must be available prior to commencing the operations.

- All well operations shall have plans to cover emergency management, oil spill contingency and blowout response.

- All proposed drilling and well operations shall be conducted in accordance with the worksite’s permit to work and SIMOPS procedures. The latter shall define the restrictions applying to the well operation and the specific procedures relating to the interaction of all proposed operations to be carried out simultaneously. Simultaneous drilling and well operations shall undergo a risk assessment for mutual impact and to identify mitigating actions.

- A Site Specific Contingency Plan must be prepared for the wells with potential H$_2$S concentration $\geq$ 300 PPM. The plan must be attached to the drilling program.

- All aquifers must be isolated prior to drilling hydrocarbon bearing zones to prevent any crossflow of hydrocarbons to aquifers.

- Casing shoes for the drilling section must be selected on the premise to:
  - Provide adequate kick tolerance to drill next section.
  - Isolate troublesome formation.
  - Achieve good cementation around casing shoe.

- The well objectives and the lifetime well requirements must be given by the Petroleum Development Division (PDD) in the prognosis, and consequently incorporated into the well design.

- The detailed drilling program must be agreed prior to commencing operations. If, during the operations, a change to the drilling program is required, then an amendment program must be signed by the Drilling Manager.
• The approved Well Delivery Limit (WDL) process for planning, implementing and assessing the performance of drilling operations must be followed on all wells.
SECTION 6

MATERIALS AND EQUIPMENT

- All materials and equipment must be procured in accordance with current ADCO procurement policies and procedures, with compliance to ADCO material standards MS-CE-98-04, STD-01, MS-CA-94-07, MS-WH-94-04.

- All materials and equipment must be fit for purpose and in compliance with the relevant ADCO and industry standards and specifications (e.g. API, NACE, ASME, ISO, etc).

- All casing materials must apply to API Spec 5CT. For H₂S (sour) service NACE standard MR0175 must be used. Where appropriate, higher specifications or standards, as required by specific situations, must be applied.

- The following table categorizes the specifications of the casing (currently) used by ADCO as minimum requirements.

Table 1-2: Minimum casing requirement for different types of wells

<table>
<thead>
<tr>
<th>Well Type</th>
<th>Csg. Size</th>
<th>Gas Producer</th>
<th>Gas Injector</th>
<th>Oil Producer</th>
<th>Oil Prod. With Gas Lift</th>
<th>Water Injector</th>
<th>Water Supply</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>87.5# Buttress ERW Or Seamless</td>
<td>87.5# Buttress ERW Or Seamless</td>
<td>87.5# Buttress ERW Or Seamless</td>
<td>87.5# Buttress ERW Or Seamless</td>
<td>87.5# Buttress ERW Or Seamless</td>
<td>87.5# Buttress ERW Or Seamless</td>
</tr>
<tr>
<td></td>
<td>13 ¾&quot;</td>
<td>L-80 68# or 72# Premium Thread (NK3SB Or N. Vam) Seamless</td>
<td>L-80 68# or 72# Premium Thread (NK3SB Or N. Vam) Seamless</td>
<td>L-55 or J-55 68# Buttress ERW Or Seamless</td>
<td>L-80 72# N. Vam ERW or Seamless</td>
<td>L-55 or J-55 68# Buttress ERW Or Seamless</td>
<td>L-55 or J-55 68# or 72# Buttress ERW Or Seamless</td>
</tr>
<tr>
<td></td>
<td>9 ¾&quot;</td>
<td>L-80 47# Premium Thread (NK3SB Or N. Vam) Seamless</td>
<td>L-80 47# Premium Thread (NK3SB Or N. Vam) Seamless</td>
<td>L-80 47# Premium Thread (NK3SB Or N. Vam) Seamless</td>
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</tr>
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<td>Well Type</td>
<td>Gas Producer</td>
<td>Gas Injector</td>
<td>Oil Producer</td>
<td>Oil Prod. With Gas Lift</td>
<td>Water Injector</td>
<td>Water Supply</td>
<td></td>
</tr>
<tr>
<td>-----------</td>
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<td>----------------</td>
<td>--------------</td>
<td></td>
</tr>
<tr>
<td>7&quot;</td>
<td>L-80 29# Premium Thread (NK3SB Or N. Vam) Seamless</td>
<td>L-80 29# Premium Thread (NK3SB Or N. Vam) Seamless</td>
<td>L-80 29# Premium Thread (NK3SB Or N. Vam) Seamless</td>
<td>L-80 29# Premium Thread (NK3SB Or N. Vam) Seamless</td>
<td>L-80 29# Premium Thread (NK3SB Or N. Vam) Seamless</td>
<td>L-80 29# Premium Thread (NK3SB Or N. Vam) Seamless</td>
<td></td>
</tr>
<tr>
<td>4 1/2&quot;</td>
<td>L-80 12.6# Premium Thread (N. Vam) Seamless</td>
<td>L-80 12.6# Premium Thread (N. Vam) Seamless</td>
<td>L-80 12.6# Premium Thread (N. Vam) Seamless</td>
<td>L-80 12.6# Premium Thread (N. Vam) Seamless</td>
<td>L-80 12.6# Premium Thread (N. Vam) Seamless</td>
<td>L-80 12.6# Premium Thread (N. Vam) Seamless</td>
<td></td>
</tr>
</tbody>
</table>
SECTION 7

WELL SITE HANOVER FROM/TO PRODUCTION OPERATIONS

- When moving to an existing cluster or to a nearby well or facility all potential risk / hazards with each activity must be identified and located on ADCO’s Risk Registry Matrix.

- A handover certificate from Production Field Services must be obtained for location and for rig move road prior to construction of a drilling site and access roads.

- The new well location will be acceptable if it meets the following requirements:
  
  o Well location must be at least 100 meters from any pipelines, production facility or power lines, and at least 500 meters from any dwellings, camp sites and blacktop (for wells with ≥ 300 ppm H₂S Site Specific Safety Plan must be made).

  o Dispensations can be made after carrying out a risk assessment (clustering and well pairing guidelines to be followed).

  o Flare lines must be correctly positioned in prevailing downwind. Avoid crossing any pipeline or laying flare line up hill. If this is unavoidable, conduct a risk assessment.

  o The site can be leveled, and is sufficiently large for the rig and any associated equipment (special site preparations are required for exploration or critical wells according to the HSEIA).

- The workover / re-entry well and location will be accepted from Production Field Services when the following requirements are met:

  o Well is secured as per criteria for safe rig entry, refer to Barrier Policies (Volume-2, Chapter-1).

  o The wellhead is safe to permit the rig installation over it.

  o All lines from wellhead are disconnected and removed.

  o Wellhead pressures must be zero prior to installing plugs and when moving rig on location.

  o High pressure gas producers and gas injectors wells if cannot be killed riglessly, rig onsite killing will be required. See pressure barriers policy (section 12).

  o Site environmentally accepted according to ADCO procedure Manual (Volume-10, HSE).

  o The cellar is clean and all valves are accessible / operatable with hand wheels.
• Crossing pipe lines or power lines is permitted only at authorized crossing points.

• All routes must be at least 30 meters from any pipe line or power lines.

• Construction of Gatch crossings over pipe lines must be authorized and agreed upon by Field Services.

• Rig site area to be surrounded by chain and cone barriers except for wells near the sea where a bunding of the location is to be done. Two gates to the location are to be in place main gate and an emergency gate.

• A handover certificate signed by both Drilling Supervisor and Field Production Supervisor must be made to handover the well site and camp site from Drilling Division to Production operations or vise versa.
SECTION 8

RIG MOVE / PRIOR TO SPUD

- If the area is specified in the Handover Certificate as hazardous, no move or preparation must be done except in daylight, and work permits must be obtained from the Field Production Supervisor on a daily basis.

- Mast and substructure must not be moved on or off wellhead except in daylight only.

- Mast lowering or raising job must be done during daylight only.

- Before raising mast, the Rig Manager must carry out a thorough inspection of the mast while in horizontal position to make sure that all components of mast sections are in good safe working condition. Only essential personnel must be in safe close proximity to the rig while raising the mast (all must avoid standing near any raising line.)

- A rig must only be moved on or off a well when that well has been secured such as to prevent the uncontrolled escape of hydrocarbons in the event of damage to the wellhead.

- In the event that a temporary X-Mas tree is to be installed prior to rig move, the pressure barriers policy must be applied.

- Rig move performance data must be submitted to the relevant DTL and to the Studies Group immediately after each rig move.
SECTION 9

WELL OPERATIONS EQUIPMENT

- The drilling Team Leader is the responsible person for ensuring that system within his team is in place to supply his rig with adequate equipment to carry out the operations safely and successfully.

- The Head of Technical (Drilling) must ensure that sufficient stocks of drilling equipment are available to carry out the drilling operations without interruptions.

- The Drilling Supervisor is responsible for ensuring that all well operations equipment that require certifications has the correct certification and that it is valid.

- Non original Manufacturers equipment or tools must not be run downhole or for surface pressure control equipment.

- The following equipment must be on the rig floor and be fully functional at all times.
  
  i. Full-opening safety valve (Kelly Cock).
  
  ii. Surface installed Inside BOP (IBOP).
  
  iii. Crossovers and lifting mechanism to allow the installation of (i) and (ii) into any connection used in the drill, tubing or completion string.
  
  iv. Casing swedge suitable for the casing string being run

Note: Gray valve must be always maintained and ready for use in case of stripping only.

- A trip tank must be available on all rigs. It must be equipped with a level indicator easily readable from the driller’s position. Such an indicator must be accurate to within one-half barrel volume.

- Upper and lower manually operated Kelly valves (full bore type) must be available at all times. On drilling rigs equipped with a top drive one of the Kelly valves is to be remotely operable from the driller’s position. It must be possible to break out a connection above the Kelly valve to insert a dart.

- Drill pipe screens to be used above the lower Kelly valve.

- Only drillpipe with no hard banding or flush ground, smooth hardfacing to be used.

- Drillpipe and bottom hole assembly components must be inspected to a minimum standard of DSTM Level-1 Category-4 once every year and as per API Standard RP-7G every well for BHA and every 4 wells for drillpipes.
• Inspection to be performed only by approved inspection companies. The inspection companies and individual inspectors must be certified, and regularly audited by ADCO and rig contractor.
SECTION 10

PRIMARY WELL CONTROL

1. Fluid in Hole

- Primary pressure control while drilling and working over will be fluid gradients. The drilling program must detail the appropriate mud gradient required for drilling under normal static conditions (based on best knowledge or prediction of formation pressures as detailed in the well prognosis provided by PDD).

- Conventional drilling, completion and workover activities must be carried out with hole full of drilling fluid of appropriate density to prevent any influx of formation fluids.

- When drilling from 0-4000 ft, the mud must provide a 50 to 100psi overbalance at the expected top of any potentially productive formation.

- When drilling hydrocarbon bearing zones below 4000 ft, the mud must provide an overbalance of 250 – 300 psi (exceptions to be approved by HDO) with appropriate risk assessment.

- After determining the formation shoe bond strength at the shoe of each casing string, the well control plan for that hole section must be agreed in the light of the information available. Refer to table (1-3)

- During workover (cased hole) operations, brines must give 300 psi overbalance at top perforations. Refer to table (1-3)

- Completion fluids must be 2 pcf higher than the mud used for drilling the horizontal hole or the zone to be perforated.

1.1 Losses

- When drilling hydrocarbon zones or with hydrocarbon zones exposed under partial loss conditions, the mud weight will be based on a balance between reducing the losses to a manageable level, and preventing kicks. Non damaging plug must be spotted to maintain the required overbalance prior to continue drilling.
  - A minimum of one and half hole volume must be kept in the tanks for emergency.

- 30 Tons (metric) of LCM must be stored on site at all times to allow continuous operations and not endanger the loss of control of the well for the contingency of weighting up to kill the well and fight losses.
• Water supply requirements are dependent on lost circulation problems. Under normal circumstances the water supply must not drop below 100 bbls/hr. For exploration wells, a minimum of 150 bbls/hr must be available.

1.2 Leak-off Test

Leak-off test must be carried out in exploration wells only or when requested by PDD and included in the well program.

1.3 Shoe Bond Testing

• Shoe bond test will be performed in all wells after drilling out 10 ft of new formation (except for conductors, 18 5/8” surface casing and horizontal holes). Corrective measures will be performed if the open hole pressure integrity fails.

Table 1-3: Surface pressures for shoe bond testing

<table>
<thead>
<tr>
<th>Casing/Formation</th>
<th>Approximate Setting Depth (ft)</th>
<th>Standard surface test pressure (psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Deep Conductor</td>
<td></td>
<td>Not required</td>
</tr>
<tr>
<td>18 5/8” Casing @ Dammam</td>
<td>1600</td>
<td>Not required</td>
</tr>
<tr>
<td>13 3/8” Casing @ Dammam</td>
<td>1600</td>
<td>Not required</td>
</tr>
<tr>
<td>13 3/8” Casing @ Rus</td>
<td>2600</td>
<td>0.65 psi/ft</td>
</tr>
<tr>
<td>13 3/8” Casing @ Fiqa</td>
<td>5700</td>
<td>0.65 psi/ft</td>
</tr>
<tr>
<td>9 3/8” Casing @ Simsima</td>
<td>4900</td>
<td>300 psi</td>
</tr>
<tr>
<td>9 3/8” Casing @ Shilaif</td>
<td>6900</td>
<td>0.65 psi/ft</td>
</tr>
<tr>
<td>9 3/8” Casing @ Bab Member or Shuaiba</td>
<td>8300</td>
<td>0.65 psi/ft</td>
</tr>
<tr>
<td>9 3/8” Casing @ Dense B</td>
<td>8500</td>
<td>0.65 psi/ft</td>
</tr>
<tr>
<td>7” Liner @ Zone B, C, D or F</td>
<td>8700</td>
<td>300 psi</td>
</tr>
</tbody>
</table>

• Shoe Bond test must be conducted after displacing hole to the new drilling mud for drilling the new hole section.

• Refer to Volume-2, Chapter-3 “Special Well Operations” for shoe bond test procedures.

1.4 Flow Checks

• Flow checks while drilling must be made if a gain or loss of 5 bbls is detected.
• Flow checks must be performed whilst tripping out of hole:
  o When pulling off bottom.
  o After pulling into the casing shoe.
  o Every 3000 ft inside casing.
  o Before the BHA enters the BOP stack.

1.5 Tripping

• Where hole is drilled across a pay zone, the Drilling Supervisor must be on the rig floor prior to each trip.

• Circulation of a minimum of one bottom up (twice bottom up for horizontal holes) or until hole clean is required.

• Flow check the well and then observe a minimum of 10 stands pulled off bottom, or until such time as the DS is satisfied that the hole fill volume is correct according to the trip sheet.

• No trip is to be made if the static loss is more than 20 bbls per hour. The hole is to remain full throughout the trip with the trip sheet monitored closely. All effort to be made to minimize losses before tripping out.

• After completing all well kills after well testing operations a minimum of one complete hole circulation is to be performed prior to pulling out of the hole.

• In open hole pipe tripping speed must be limited to one stand per 30 seconds to avoid swabbing or surging the hole.

• When an influx of formation fluid into the well bore is detected the well must be shut in immediately using the Hard Shut In Method using the annular BOP first.

• Special tripping practices for sour gas wells must be made prior to POOH, this includes short trip of 5 stands to ensure hole is not swapped. A pill of scavenger must be spot on bottom.

1.5.1 Trip Sheets

Trip sheets must be filled out by the driller on every trip in and out of the hole every 5 stands of DP’s and every 2 stands for DC’s. Any deviation from expected hole fill up volumes must be investigated immediately as per IWCF procedures.
1.6 Slow Pump Rate (SPR)

Two Slow Pump Rate at 30 SPM and 45 SPM for each pump must be taken at least:

- Start of tour
- At a bit or BHA change
- Every 500 ft.
- When the mud weight is changed

Pressure must be recorded using the same gauge to be used for killing operations.

1.7 Equipment and Mud Materials

The following kick detection / equipment / instrument is the minimum required to be operational on Categories (A) High Risk Wells and (B) Medium Risk Wells.

- Active pit volume monitors.
- Flow indicator equipment on flowline.
- Gas detection at flowline and shale shaker.
- Geolograph recorder (ROP, torque, string weight, flowrate and pressure) must always be operable records to be held, and supplied to town on request.
- Mud weight in and out (mud balance).
- Trip tank with level indicator.
- Minimum stock of 50 tons of barite or CaCO₃ for development wells and 100 tons for exploration wells to be on location.
- A minimum volume of 1000 bbls completion fluid must be maintained until wellhead is secured and rig released.
SECTION 11
SECONDARY WELL CONTROL-WELL CONTROL EQUIPMENT

1. General

- Secondary well control is the well control equipment including the diverter system, BOP stack, BOP control system, wellhead, casing, Kelly cocks, Kelly hose, drillstring safety valves, kill and choke lines, kill and choke manifold, mud gas separator and all associated pipework and valves.

- A BOP must be installed for drilling operations below the surface casing shoe on all wells penetrating hydrocarbon or aquifer formations which are capable of sustained natural flow to surface.

- In situations during drilling and well operations where the BOP stack cannot close in effectively to contain maximum expected surface pressure (for example running cables, control lines, etc), risk assessment must be carried out to determine the acceptability and reliability of contingency plans for securing the well in the event of a well control incident.

- All wireline and coiled tubing operations must be carried out through a BOP and lubricator System that must contain well pressure while the cable or tubing is moving through the wellhead.

- BOP and choke manifold must be set up for hard shut-in

- The BOP stack and wellhead used at any point during the course of the well must be of sufficient working pressure to contain the greatest anticipated surface pressure. The highest anticipated wellhead pressure for Category (A) High Risk Wells must take into account a gas column to surface, whilst for Categories (B) Medium Risk Wells and (C) Low Risk Wells reservoir fluid to surface must be used. The maximum anticipated wellhead pressure will be defined in the well programme. Consideration must also be given in all cases to pressures imposed by testing and stimulation.

- The Head of Drilling Operations and Drilling Manager must be made aware of any well control equipment which is not in full working order.

- Kick and kill drills must be held regularly until the Drilling Supervisor is satisfied that a good standard has been achieved by the rig crew.

- A well control incident report will be completed immediately following any well control incidents.
2. BOP Components

- The BOP stacks must consist of an annular preventer and the number of ram-type preventers as specified later in this section. The pipe rams must be of a proper size(s) to fit the drill pipe, casing or tubing in use.

- All BOP systems must be equipped and provided with the following system components:
  - An accumulator system which must provide sufficient capacity to supply 1.5 times the volume of fluid necessary to close and hold closed all BOP equipment units with a minimum pressure of 200 psi above the precharge pressure without assistance from a charging system.
  - Accumulator regulators supplied by rig air and without a secondary source of pneumatic supply, must be equipped with manual overrides or alternatively, other devices provided to ensure capability of hydraulic operations if rig air is lost.
  - A backup to the primary accumulator charging system which must be automatic, supplied by a power source independent from the power source to the primary accumulator charging system, and possess sufficient capability to close all BOP components and hold them closed.
  - At least one operable remote BOP control station in addition to the one on the drill floor. This control station must be in a readily accessible location away from the drill floor.
  - A drilling spool with side outlets; if side outlets do not exist in the body of the BOP stack to provide for separate kill and choke lines.
  - A choke and kill line each equipped with two full opening valves. At least one of the valves on the choke line must be remotely controlled. At least one of the valves on the kill line must be remotely controlled except that a check valve must be installed on the kill line in lieu of the remotely controlled valve provided two readily accessible manual valves are in place and the check valve is placed between the HCR valves and the pump.
  - A fill-up line above the uppermost preventer.
  - A choke manifold suitable for the anticipated pressures to which it may be subjected.
  - Manifold and choke equipment subject to well and/or pump pressure must have a rated working pressure at least as great as the rated working pressure of the ram-type preventers.
  - Valves, pipes, flexible steel hoses, and other fittings upstream of, and including, the choke manifold with pressure ratings at least as great as the rated working pressure of the ram-type preventers.
• On a conventional rig, a kelly cock installed below the swivel (upper kelly cock), essentially full-opening, and a similar valve of such design that it can be run through the BOP stack (strippable) installed at the bottom of the Kelly (lower Kelly cock).

• On a top-drive system equipped with a remote controlled valve, a second and lower strippable valve of a conventional Kelly cock or comparable type either manually or remotely controlled.

• An Inside BOP and an essentially full-opening drill-string safety valve in the open position on the rig floor at all times while drilling operations are being conducted.

• Provision must be made to double valve all active openings from the well to the atmosphere. The valve closest to well pressure must be considered as a master valve to be used only in the event repair of the secondary valve is required.

• A Diverter must be used in shallow sections of hole to direct the flow of hydrocarbons or formation water to atmosphere where the MAASP does not permit the closing in of the well (weak casing shoe or formation).

• The diverter system (diverter sealing element, diverter lines, and control systems), must be designed, installed and maintained so as to divert gases, water, mud, and other materials away from the facilities and personnel.

3. BOP’s Classification and Minimum Requirements

BOP’s systems in ADCO are classified to three classes:

1) Class (I) BOP Stack consists of
   • 1 Annular 5000 psi
   • 3 Rams 10000 psi (35% H₂S Materials)

2) Class (II) BOP Stack consists of
   • 1 Annular 5000 psi
   • 3 Rams 5000 psi (35% H₂S Materials)

3) Class (III) BOP Stack consists of
   • 1 Annular 5000 psi
   • 2 Rams 5000 psi (35% H₂S Materials)

4) Class (IV) BOP Stack consists of
   • 1 Annular 5000 psi
   • 2 Rams 5000 psi (5% H₂S Materials)
3.1 BOP Stack Minimum Requirements

BOP stack configuration may vary with the degree of risk associated with the drilling operation. Following the BOP stack minimum requirements.

- BOP shall be pressure rated to close on the maximum anticipated reservoir pressure in the event of loss of well control.

- The minimum BOP configuration for BOP stacks used on wells where a surface pressure up to and including 4500 psi is possible is:
  - One Annular preventer
  - Two Rams type preventers

- The minimum BOP configuration for BOP stacks used on wells where a surface pressure of over 4500 psi is possible is:
  - One Annular preventer
  - Three Rams type preventers

- All stacks will incorporate one set of blind or blind/shear rams.

- Shear ram must be able to shear and seal any pipe planned to be run through the BOP stack.

- Manufacturer’s certification for compliance with NACE Standard MR0175 must be available and reviewed for all well control equipment.

- For wells where H₂S content is > 5%, all BOP rams must be fitted with 35% H₂S elastomers.

- For wells where H₂S content is < 5%, all BOP rams must be fitted with 5% H₂S elastomers.

- The BOP elastomeric components that may be exposed to well fluids must be verified by the BOP manufacturer as appropriate for the drilling fluids to be used and for the anticipated temperature to which they are exposed.

- All stacks will incorporate at least one choke line and one kill line which enters the stack above the lower most set of rams.

- Kill and choke lines, installed below the lower most set of rams, will normally be used for pressure testing or monitoring the well only.

- Dual rams must be installed when running dual completion.
• The lower most ram must be preserved as a master valve and should not be used as a stripping ram.

• Dual full opening valves must be provided on each choke/kill line for all stacks. One valve on the choke line must be remotely activated.

• Ram type preventers will have ram locking devices (Mechanical) installed.

• The kill line must have double isolation from the standpipe manifold.

• The kill line must have an operated kill valve or an NRV as a means of preventing flow of wellbore fluids into the wellhead area should the kill line fail.

• Refer to Chapter-3, Section-7 for BOP stack testing procedure.

4. Pressure Rating

The working pressure rating of any BOP component must exceed the anticipated surface pressure to which it may be subjected (safety factor employed as per API standards).

5. \( \text{H}_2\text{S} \) Environment

When operating in an \( \text{H}_2\text{S} \) environment, the equipment must be constructed of materials with metallurgical properties that resist or prevent sulfide stress cracking (also known as hydrogen embrittlememt, stress corrosion cracking, or \( \text{H}_2\text{S} \) embrittlememt). All BOP system components, wellhead, pressure control equipment, and related equipment exposed to \( \text{H}_2\text{S} \) bearing fluids must conform to NACE Standard MR.01-75- latest edition.

Blowout preventer systems on ADCO’s rigs are rated to 5% or 35% \( \text{H}_2\text{S} \) as follows:

<table>
<thead>
<tr>
<th>Rig</th>
<th>( \text{H}_2\text{S} ) Rating (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>NDC-1, NDC-2, NDC-8 and NDC- 10</td>
<td>5</td>
</tr>
<tr>
<td>NDC- 9, NDC- 16, NDC- 17, NDC- 21, NDC- 22, NDC- 11, NDC-24, NDC- 25, NDC-31, NDC-32, NDC-33 and NDC- 34</td>
<td>35</td>
</tr>
</tbody>
</table>
6. Tapered Drill Pipe Operations

Prior to commencing tapered drill pipe operations, the BOP stack must be equipped with conventional and/or variable bore pipe rams installed in one or more ram cavity to provide a sealing around the larger size drill pipe and smaller size of drill pipe.

7. Modifications, Changes and Repairs

- All modifications, design changes or weld repairs to well control equipment must comply with and be certified by the manufacturers.

- Original equipment manufacturers spare parts must be used at all times.

- Well control equipment that has been subject to any design change, modification or body repair is to be tested to its full test pressure and, if applicable, re-certified before use. Where repairs entail change out of parts only a pressure test to the full working pressure only is required.

8. Well Control Training and Drills

- Each driller, Rig Manager, Drilling Supervisor, Mud Engineer, Drilling Engineer, Senior Operations Engineer and Drilling Team Leader must have a valid well control certificate for land drilling operations that meets the IWCF standard.

- Well control certificate must be current and renewed prior the expiry date.

- Well control drills must be conducted for each drilling crew in accordance with the frequency in Chapter-3 “Well Control” of this Volume.
SECTION 12

PRESSURE BARRIERS

1. Well Barrier Design Principles

   • Barrier: Is an envelope preventing flow of formation fluids to another formation or to surface. It consists of one or several independent elements

   • The well barriers must be designed, selected and/or constructed such that:
      o it can withstand the maximum anticipated differential pressure it may be exposed to,
      o it can be leak tested and function tested or verified by other methods,
      o no single failure of well barrier leads to uncontrolled outflow from the borehole / well to the external environment,
      o re-establishment of a lost well barrier or another alternative well barrier can be done,
      o it can operate competently and withstand the environment for which it may be exposed to over time,
      o its physical location and integrity status is known at all times.

   • One of the well barriers must have well barrier element(s) that can
      o seal the well bore with any size tool that penetrates the well barrier. If this is not achievable, well barrier descriptions for operational situations which require shearing of tools must be identified.

   • If a barrier fails, immediate action must be taken to re-instate or replace the failed barrier.

   • A pressure tested bottom wireline plug must only be considered a barrier if kill brine is on top (upward facing seals have not been tested). (N.B., the plug and kill brine are not independent and must therefore be regarded as a single barrier).

   • A tubing hanger is used as a barrier if it has been pressure tested from below or through the test port.

   • A cement plug may be considered a barrier if it has been tagged and pressure tested, or inflow tested. The pressure test must be greater than the fracture gradient of the formation below the cement plug.
• A casing and shoetrack with floats is considered a barrier if successfully pressure tested (e.g., at the bump) and the floats have been inflow tested (e.g., against the pressure differential of the cement column.

• A SCSSSV may be used as a bottom barrier provided that:
  o Sufficient well pressure is available to force the valve closed
  o The inflow test against the full pressure differential showed a zero leaks rate

2. Barrier Types

There are 3 types of barriers

1) Closed mechanical barrier
   (e.g., wireline plug, monolock, cement plug, casing and casing shoe with floats)

2) Open mechanical barrier
   (e.g., BOPs)

3) Liquid barrier
   (e.g. overbalanced mud)

Notes:

• An open barrier must only be considered as a `barrier' when all systems for closing that barrier are available and ready to function (e.g. BOPs are fully operational).

• BOPs and X-mas trees have multiple shut rams or valves. Even when multiple rams or valves are closed, the BOP or X-mas tree must be regarded as a single barrier.

3. Mechanical Barrier Integrity

• Individual barriers which are normally open must be regularly tested, in accordance with their specific test criteria.

• Barriers which are normally closed must be tested at the time of installation.

• Testing of a barrier must be in the direction of the anticipated flow. If testing in the direction of the anticipated flow is not possible, the mechanical barrier must only be considered acceptable if special design considerations are made.

• All mechanical barriers must be leak tight.

• Inflow tests for mechanical barriers must be held for a minimum of 30 minutes against the full pressure differential, with zero pressure build up.
Pressure tests of mechanical barriers must be held for a minimum of 15 minutes against the maximum anticipated pressure differential, with zero pressure decline.

4. **Fluid Barrier Integrity**

- If partial mud losses are present (even small losses) the mud level must be monitored continuously.

- A water column under total loss conditions, continuously topped up from surface at a specified minimum rate is referred to as a "dynamic water column". Under strict controls, a dynamic water column may be considered a barrier for Medium Risk Wells.

- In a well with a static mud column, the casing packer may be shallow set (e.g. 150 to 200 ft below the drill floor), with the unobserved static mud column acting as a barrier. Under partial loss conditions, or if brine is used, the casing packer must be deep set (i.e. below the static fluid level). Also, the fluid column above it must be continuously monitored. Tail pipe below packer must be as close as possible to the reservoir.

5. **Minimum Pressure Barriers Requirements**

The minimum acceptable pressure barriers in ADCO to perform specific well operations for each category of wells are summarized below.

5.1 **During Replacing Tubing Head Spool**

Table 1-5: Pressure Barriers Required During Replacing Tubing Head Spool

<table>
<thead>
<tr>
<th>Water Injectors (Except Bab Mid Dip Injectors)</th>
<th>Oil Wells (and Bab Mid Dip Injectors)</th>
<th>Gas Wells Producer, Injectors</th>
</tr>
</thead>
<tbody>
<tr>
<td>2 Barriers (1 Mechanical and 1 Hydraulic)</td>
<td>3 Barriers (2 Mechanical &amp; 1 Hydraulic)</td>
<td>3 Barriers (2 Mechanical &amp; 1 Hydraulic)</td>
</tr>
<tr>
<td></td>
<td>Cemented casing with non drilled shoe track is a Barrier that can substitute the 2 Mechanical Barriers</td>
<td></td>
</tr>
</tbody>
</table>
# 5.2 During Rig Move On/Off Wellhead

**Table 1-6: Pressure Barriers Required During Moving Rig on/off wellhead**

<table>
<thead>
<tr>
<th>Status Prior to Installing Barriers</th>
<th>Water Injector Wells (Except Bab Mid Dip Injectors)</th>
<th>Oil Wells (and Bab Mid Dip Injectors)</th>
<th>Gas Wells Producer, Injectors</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Tubing</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>No Pressure</td>
<td>1 Surface Barrier</td>
<td>2 Mechanical Barriers (Minimum 1 Subsurface)</td>
<td>3 Barriers (Minimum 1 Mechanical Subsurface &amp; 1 Hydraulic)</td>
</tr>
<tr>
<td>Pressure</td>
<td>2 Barriers (Minimum 1 Subsurface Mechanical)</td>
<td>3 Barriers (Minimum 1 Mechanical Subsurface &amp; 1 Hydraulic)</td>
<td>3 Barriers (Minimum 1 Mechanical Subsurface and 1 Hydraulic)</td>
</tr>
<tr>
<td><strong>Annulus</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>No Pressure</td>
<td>1 Surface Barrier</td>
<td>1 Surface Barrier</td>
<td>1 Surface Barrier</td>
</tr>
<tr>
<td>Pressure</td>
<td>Risk Assessment and management approval are required</td>
<td>Risk Assessment and management approval are required</td>
<td>Risk Assessment and management approval are required</td>
</tr>
<tr>
<td>Pressure can not be isolated</td>
<td>Risk Assessment and management approval are required</td>
<td>Risk Assessment and management approval are required</td>
<td>Risk Assessment and management approval are required</td>
</tr>
<tr>
<td>Pressure can be isolated</td>
<td>2 Barriers (Minimum 1 Hydraulic)</td>
<td>2 Barriers (Minimum 1 Hydraulic)</td>
<td></td>
</tr>
</tbody>
</table>
### 5.3 During Removing / Installing BOP / X-Mas Tree

Table 1-7: Pressure Barriers Required During Removing / Installing BOP / X-Mas Tree

<table>
<thead>
<tr>
<th>Status Prior to Installing Barriers</th>
<th>Water Injector Wells (Except Bab Mid Dip Injectors)</th>
<th>Oil Wells (and Bab Mid Dip Injectors)</th>
<th>Gas Wells Producer, Injectors</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Tubing</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>No Pressure</td>
<td>1 Surface Barrier</td>
<td>2 Barriers (Minimum 1 Mechanical Subsurface)</td>
<td>3 Barriers (Minimum 1 Mechanical Subsurface &amp; 1 Hydraulic)</td>
</tr>
<tr>
<td>Pressure</td>
<td>1 Surface Barrier</td>
<td>2 Barriers (Minimum 1 Mechanical Subsurface)</td>
<td>3 Barriers (Minimum 1 Mechanical Subsurface and 1 Hydraulic)</td>
</tr>
<tr>
<td><strong>Annulus</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>No Pressure</td>
<td>1 Surface Barrier</td>
<td>2 Barriers (Minimum 1 Hydraulic)</td>
<td>2 Barriers (Minimum 1 Hydraulic)</td>
</tr>
<tr>
<td>Pressure can not be isolated</td>
<td>Risk Assessment and management approval are required</td>
<td>Risk Assessment and management approval are required</td>
<td>Risk Assessment and management approval are required</td>
</tr>
<tr>
<td>Pressure can be isolated</td>
<td>2 Barriers (Minimum 1 Hydraulic)</td>
<td>2 Barriers (Minimum 1 Hydraulic)</td>
<td>Risk Assessment and management approval are required</td>
</tr>
</tbody>
</table>
SECTION 13

PRESSURE TESTING

1. General

- Rig crew must be alerted when pressure test operations are underway. No one must remain in the test area.
- All tests must be performed using clear water.
- Should any of the tests identify faulty equipment, drilling operations must be suspended and well secured, if needed, until the faulty equipment is repaired or replaced.
- All valves located downstream of the valve being tested must be placed in the OPEN position.
- All pressure tests must be held for a minimum duration of 5 minutes with no observable pressure decline.
- Pressure should be released only through pressure release lines.
- Only authorized personnel go in the test area to inspect for leaks when the equipment is under pressure.
- All lines and connections that are used in the test procedure should be adequately secured.
- Tightening or repair work must be done only after pressure has been released and all parties have ensured that there is no possibility of trapped pressure.
- All pressure tests must be conducted with a test pump. Avoid the use of rig pumps for pressure testing. Cement units are acceptable.
- All test result must be documented in addition to the pressure chart, with the following information,
  - Date of test
  - Well Name
  - Driller Name
  - RM Name
  - DS Name
2. Pressure Testing of Well Control Equipments

- BOP equipment must be pressure tested as per the following criteria:
  o When installed.
  o Before drilling out each string of casing.
  o Following the disconnection or repair of any wellbore pressure seal in the wellhead/BOP stack (limited to the affected components only).
  o After a maximum of 14 days from last pressure test.

- All BOP pressure tests must be witnessed by Drilling Supervisor and Rig Manager.

- A pressure test is required after the installation of casing rams. This test is limited to the components affected by the disconnection of the pressure containment seal.

- All well control equipment except annular BOP’s is to be tested to the lowest of the following criteria after the installation of any wellhead body component or prior to drilling out cement inside each casing string.
  o Maximum anticipated wellhead pressure to be encountered in the hole section being drilled.
  o 70% of casing burst pressure.
  o Wellhead rated pressure.
  o BOP rated pressure.

Note: In the event that the maximum anticipated wellhead pressure is not known with reliability, then the well control equipment should be tested to the lowest of the criteria above.

- Annular preventer will be tested to a minimum of 70% of the rated working pressure.

- Annular preventer should be tested with the smallest OD pipe to be used.

- All high pressure connections associated with the well control equipment are to be pressure tested upon the installation or reinstallation of each connection.

- The volume of test fluid must be monitored and recorded. The opening and closing volumes of all BOP functions must be monitored and recorded.

- All casing pack-offs are to be pressure tested.

- When testing wellhead components due consideration must be given to burst and collapse rating of relevant casing and components.
• Well control equipments that has been subject to any modification or body repair is to be pressure tested and, if applicable, re-certified before use.

• Wellheads and drilling spools must have full bore double valve isolation whilst the wellhead is in communication with open formation. The non-active spool side outlet should have a Valve Removable Plug (VRP) installed to enable the installation of valves if necessary.

• Refer to Chapter-3 Well Control, Section-7 for detailed BOP testing procedure.

3. Tubular Pressure Testing

3.1 Pressure Testing of Casing

• All surface, intermediate and production casing/liners shall be pressure tested prior to drilling out the shoe track or perforating.

• For surface and intermediate casings/liners the minimum pressure test must be the highest of:
  o Calculated surface pressure required to perform the planned leak off test plus a test margin. The recommended test margin for development wells is 0.06 sg (4 pcf).
  o Calculated pressure for circulating out maximum kick as used in casing design calculations.

• For production casing/liners, the minimum pressure test must be equivalent to the shut in tubing pressure on top of the annulus completion fluid.

• Any additional loads that are to be placed on the casing string (e.g. operating annulus pressure controlled test tools) must also be taken into account when planning pressure tests).

• Test pressures must not exceed any of the following:
  o 70% of burst pressure of the weakest casing.
  o Wellhead rated pressure.
  o BOP rated pressure

• Due consideration must be given to the following factors:
  o The burst rating of the weakest casing in the string.
  o The density of the mud columns inside and outside the casing.
  o The minimum design factors assumed in the casing design.
  o The effect of pressure testing on casing tensile loads.
• Production casing strings that are to be used in a well for production or injection operations must be designed and pressure tested to the maximum possible wellhead pressure.

• Liner overlaps will be positively pressure tested to a minimum of 500 psi over formation leak-off pressure of previous casing; if there is any doubt, an inflow test must be carried out, with a sufficient drawdown to test the liner top to the most negative differential pressure that will exist during the life on the well.

• The test pressure and method for each well are determined on an individual basis

• Casing wear and consequent reduction in casing strength must be considered during planning of drilling and well testing operations.

3.2 Testing completion string

• Production or test tubing must be tested to the maximum anticipated surface pressure as a minimum. The pressure test for the production tubing can be increased to give an internal pressure at the lower section of tubing or packer assembly equivalent to the pressure load from the SITP and produced fluid.

• Pressure testing of tubing is dependent of the completion design and must be considered as part of the running procedure. Consideration must be given to future injection pressures.

• Tubing sub-assemblies must be made up and tested with water in the tubular tong contractor workshop according to the specific completion requirements. Test to be witnessed by ADCO representative before they are sent to the rig ready to be run. Gas well tubing sub-assemblies must be gas tested in tubular tong contractor workshop as above.

3.3 Testing X-Mas Tree

• X-mas trees must be tested to the rated working pressure using hydraulic oil then to be filled with inhibited diesel.

• Gas wells X-mas trees must be bubble tested using nitrogen then filled with inhibited diesel.
SECTION 14
CASING

1. General

- The Casing Seats of the Conductor Pipe and Surface Casing must be set at a depth and into a formation carefully selected so that to prevent potential Ground Subsidence underneath rig substructure. This may occur following severe losses while drilling unconsolidated formation through one or two joints of conductor pipe.

- The casing scheme for a well must be designed to provide for the containment of well fluids, pressures and to isolate the aquifers and hydrocarbon bearing zones from surface and each other.

- Prior to drilling UER and Simsima, the unconsolidated surface formation must be isolated by a cemented casing set into Dammam formation or deeper.

- Casing points must be selected to provide a reasonable kick tolerance when drilling through potential hydrocarbon bearing zones.

- No hydrocarbon zone and aquifer must be behind one casing string. A casing string with shoe tested must separate the aquifers from the hydrocarbon zones.

- A casing design will be performed for all wells using the above criteria.

- Except for conductor pipe, all casing strings must have at least two float valves installed.

- If auto fill casing float equipment is used, it must be tripped prior to running. Casing to be filled every 3 joints using Auto fill circulating head.

- Casing must be pressure tested prior to drilling out the casing shoe track.

- All production casing/liner must be designed for burst to withstand the maximum pressure resulting from tubing leak at the wellhead applied over the packer fluid.

- Only seamless grades of tubular are acceptable for premium connection casing and tubing.

- Only premium connections are acceptable for casing and tubing which may be exposed to reservoir (13 ⅜” casing in case of gas and WAG wells must be of premium connection).

- DV’s and DV packers are not to be used in the production casing to avoid potential leak points.
2. **Casing Classification**

Casing strings in ADCO are classified as follows:

2.1 **Shallow Conductor Pipe**

Consists of a minimum of one joint and a maximum of 3 joints of conductor pipe, and must be solid cemented to surface.

2.2 **Deep Conductor Pipe**

Consists of a minimum of four joints and a maximum of 7 joints of casing, and must be fully cemented to the surface.

2.3 **Surface Casing**

Must be set into top Dammam as a minimum or into top Rus as a maximum. This casing may be waived in some applications and must be fully cemented to surface.

Setting depth is determined after a careful study of the geological conditions.

2.4 **Intermediate Casing**

Must be set into top RUS formation as a minimum or deeper to cover UER and Simsima to set shoe into top Fiqa.

This casing may be waived in some applications and must be fully cemented to surface.

Setting depth is determined after a careful study of the geological conditions.

2.5 **Production Casing**

May be set above or through the production or injection zone and is run to provide borehole integrity during the life of the well. Casing must be set at a depth determined after a careful study of the geological conditions and must be fully cemented to the surface.

It must not be set through reservoirs if aquifers are not cased off.

2.6 **Production Liner**

Provides a separation for the productive horizons from other reservoir formations. Production liner must be fully cemented to the top of the liner.
3. Casing Design Factors

Casing must resist burst stresses and collapse forces. It must also have sufficient tensile and compressive strength, and needs to retain its properties under sour service conditions.

The casing design factor is defined as the ratio of the casing resistance to the actual load (respectively in collapse, burst, tension, compression and triaxial).

The following minimum design factors must be applied:

- **Minimum Design Factor for Collapse** = 1.00. The collapse loading is determined by assuming an evacuated casing and applying a mud pressure gradient to the outside of the casing.

- **Minimum Design Factor for Burst** = 1.10. The burst loading is calculated by assuming that the bottom hole pressure is exerted over the length of the casing string external gradient of mud.

- **Minimum Design Factor for Tension** = 1.30. The tensile loading calculations assume the full casing weight in air.

- **Minimum Design Factor for Compression** = 1.00. Compression loads are generated in casing strings from a combination of buoyancy, Poisson's effect or (reverse) ballooning, thermal expansion, borehole friction or drag in directional wells, and slack-off. Buckling and bending induce compressive axial stresses in casing. These bending stresses must be evaluated using a computer model.

- **Minimum Design Factor for Triaxial Load (Von Mises Combined Load)** = 1.25

**Note**

_The Landmark Graphics Casing Design software “Stress Check™”, or similar, must be used in case of low geothermal gradient to calculate the triaxial stress. While “Well Cat™ from Landmark” is recommended for wells where temperature effect is relatively high and more sophisticated simulation is required (HTHP wells, High geothermal gradients)._
SECTION 15

CEMENTING

1. General

- Cementation of wells must be designed to ensure well integrity over the life of the well, isolation between reservoir sub zones, and to prevent gas and fluid migration from one zone to another, during well life and after abandonment.

- Every well must have a cementing program that includes the following information:
  - Planned tops of cement.
  - Cement slurry design.
  - Casing centralization program.
  - Pumping displacement rate recommendations.
  - Excess volume to be pumped for each cement job.
  - Spacer composition and volume.
  - Thickening time of the slurry.

2. Material Safety Data Sheet

All safety related properties of cementing chemicals and the necessary handling procedures must be known. Material safety data sheets must be available at the rig site for all cementing chemicals with copies available to the drilling contractor. Consideration at the cementation planning stage must be given to toxicological properties.

3. Sampling and Lab Tests

Prior to cementing of casing strings, representative samples of cement, additives and mixing water must be taken. Laboratory testing in accordance with API and ADCO procedures (as appropriate) of each cement slurry will be conducted prior to the cementation of 7” liners or casing string across hydrocarbon zones.

Communication with rig will be by fax (verbal communications are not permitted).

4. Bumping of Plugs

- The cementing plug is to be bumped using the theoretical volume. If it is not bumped, then no over displacement is permitted.

- If the cement plug is bumped, the casing is to be tested accordingly to maximum 70% of it burst pressure.
SECTION 16

CORING

- All coring tools strings must be equipped with a circulating sub above the core barrel to be activated in case of well control situation. The ball seat ID of the circulating sub must allow the ball of the core barrel to pass through.

- For H₂S wells, special trip out procedures to be followed to minimize H₂S and gas expansion on surface. Airloop and all H₂S precautions to be followed on rig floor while recovering the core.

- Caravan used for cutting cores and core preservation must be equipped with Exhaust fan.

- Breathing Apparatus must be used while recovering and cutting cores with H₂S content.
SECTION 17

LOGGING AND PERFORATION

1. General

- The Drilling Supervisor has the overall responsibility for all logging and perforating operations carried out on a drilling rig. Logging operations will only proceed when the Drilling Supervisor consider the hole conditions present no risk to the safety of personnel and drilling installation.

- Open hole logging will only be carried out under conditions where:
  - The hole can be contained, monitored and controlled and where the drilling fluid provides the necessary overbalance.
  - The hole conditions are considered suitable for the tools that are to be run.
  - Appropriate pressure control equipments are used.

- In situations where a wireline BOP’s riser or lubricator are used they must be pressure tested to the maximum anticipated wellhead pressure, prior to running a wireline tool into the wellbore.

- TLC tools must be used in wells with H₂S content is more than 20%.

- For sour gas wells, full detailed HAZOP study must be made for logging.

2. Perforating

- All perforating operations must only be conducted under conditions where the hole can be contained, monitored and controlled.

- Perforating of all well categories must be conducted in a manner to allow the circulation of any well bore influx consequent to the perforation. This can be achieved by running the perforating guns through open ended drill pipe or, where the guns are too large to run through drill pipe, by utilizing tubing conveyed perforating (TCP) guns with a suitable circulation device to be opened in case of a well control situation.

- Only the responsible contractor must handle all onsite explosives and radioactive sources. This must be performed:
  - According to local government and Company safety regulations.
  - Using suitably qualified and authorized personnel.
  - Maintaining an accurate log of such materials and their usage.
Radio silence procedures approved by the appropriate local management will be in place for all tools that use explosives and will be adhered to at all times. Examples of tools included in this as follows:

- Wireline perforation guns (except approved radio safe guns).
- Tubing conveyed perforating guns (electronically detonated).
- Formation sampling tools (explosive types only).
- Backoff shots.
- Bridge plugs, cement retainers and packers run on wireline.

When POH with fired gun. All precautions to be taken on rig floor assuming the gun did not or had partially fired.

For sour gas wells, full and detailed HAZOP study must be made.

For sour gas wells, all down hole and surface equipment must be H₂S resistant.

### 3. Radio Active Sources

- All personnel handling radioactive sources must wear approved film badges or dosimeters.

- If LWD tools are left in hole that contains a radio active source, all attempts are to be made to recover the radioactive source prior to commencing fishing operations. Exceptions to be approved by HDO / DM.

- The consequences of leaving radioactive source in hole must be assessed and clearly reported even if the hole is abandoned.

#### 3.1 Minimum Requirements for Radioactive Source Abandonment

- Submit the abandonment proposal to head of radiation control section, UAE ministry of electricity & water. The radioactive source shall not be abandoned unless a formal written approval is obtained from the ministry.

- Approval by both the well permitting agency and the radiation – licensing agency.

- Hydraulic seal, normally a cement plug, 200 ft long (use colored cement as a warning to anyone in future that tries to drill it out).
• Mechanical protection of the source from damage due to further attempts at drilling or deepening (normally a whipstock shoe or other deflection device above the cement plug)

• A plaque at the wellhead, stating the presence of the source in the hole and a warning to avoid mechanical damage to the source.
SECTION 18

PRODUCTION TESTING

- The Drilling Supervisor is in overall charge and responsible for all testing operations.

- All well testing operations will be performed in accordance with the relevant Well Testing chapter of this manual where applicable.

- A detailed program for any testing operation must be prepared and approved prior to the commencement of operations.

- A pre-test meeting must be held on-site with all the relevant Company, Drilling Contractor and Service company personnel present.

- For wells of category (A) and (B) a risk assessment is to be conducted.

- For sour gas wells, full and detailed HAZOP study must be made.

- The test string must include the facility to allow the string contents to be circulated prior to pulling out of hole. Tubing may be punched using wireline tubing puncher.

- All downhole testing and completion equipment (except tubulars) must be pressure tested to the maximum anticipated operating pressure plus a safety margin prior to running into the wellbore (pre-tested subassemblies may be used).

- The test string tubing must be pressure tested to the maximum anticipated flowing pressure plus a safety margin prior to flowing the well.

- All testing strings must have a surface controlled sub surface safety valve installed.

- All testing string tubing and components must have premium connections

- Packer fluid must be inhibited against corrosion and have an over balance of 300 psi above the original producing formation pressure.

- Open hole testing operations where the packer is set in open hole will not be conducted. Production test packer must be set inside casing.

- All surface well testing or completion equipment upstream of the choke must be pressure tested to the maximum anticipated pressure plus a safety margin prior to flowing the well. Equipment downstream of the choke must be tested to rated working pressure. A full function test of all valves and automatic systems must be conducted.
The air supply to green burners must be independent of the rig air supply. Non-return valves must be fitted between the compressors and burner head.

Test lines, flare lines and valves must be securely anchored.

Flanged flow lines must be used for sour gas wells.

All trees must have two operatable valves providing double isolation at all outlets. An actuated valve on upper master and wing valve must be used in exploration or gas well testing. X-mass tree must be flushed and greased after each acid job.

ESD stations with low pressure switch on pump must be used.

ADCO HSE policies and regulations must be applied in particular with regard to following:

- Airloop system must be installed on all wells containing H₂S, on rig floor and around testing equipment.
- Oil produced must be pumped to the nearest facility.
- Green burners must be used for gas flaring.
- Vertical flare stack must be used for sour gas wells.
- Acid must be neutralized prior to disposal in a non-sensitive areas.
- Crude oil or formation water containing H₂S must be sweetened prior to storage, pumping to station or transfer.

Hydrocarbons present in the well upon starting workover operation must be bullheaded into formation if possible, other wise, pumped to production facility. The returns can be directed to shale shakers only if DS is sure that no hydrocarbon with the returns. However this must be done with caution, so that the returns must be directed immediately to the poor boy degasser once any hydrocarbon, oil or gas, is observed.

Flare line length must meet the following criteria.

- A minimum of 2000 ft for categories (A) High Risk Wells and (B) Medium Risk Wells.
- A Minimum of 1000 ft for category (C) Low Risk Wells

Contingency plans must be in place whenever coiled tubing is down hole for possibility of failure.

While B.H. sampling the wireline and lubricator must be tested again after the sampling device is run at depth.

No B. H. sampling is to be carried out in high H₂S wells.
• All wireline or coiled tubing (CT) work in high H₂S wells must not be carried out when the tubing is full of gas. The tubing must be bullheaded with inhibited fluid prior running wireline tools or CT.

• No coiled tubing is to be run in gas wells where the tubing is full of gas. No attempt to flow the gas well is to be made if CT is in hole.
SECTION 19

COMPLETION

1. General

- The Drilling Supervisor is in overall charge and responsible for all completion operations.
- All completion tubing and components must have premium connections.
- Completions must be designed to contain the maximum operating pressure anticipated during the life of the well.
- All X-mas trees must have two operatable valves providing double isolation at all outlets.

2. Subassemblies

All downhole completion equipment (except tubulars) must be made up, assembled in sections, pressure tested to the maximum anticipated operating pressure plus a safety margin in the tubular tong contractor workshop and sent to the rig. Gas well subassemblies are to be gas tested.

3. SCSSV’s

All hydrocarbon producing wells must have a surface controlled subsurface safety valve installed. For water injection wells, a sub surface safety valve is not required unless the well is located in mid dip reservoirs.

4. Production Packer

All wells must have an annular isolation production packer installed, except in case of ESP completion, which must be decided on case by case basis. In gas production wells the production packer must be a permanent type (gas lift wells are an exception).

5. Completion Fluid

- Completion fluid must contain corrosion inhibitor and Biocide and have an over balance of 300 psi above the producing formation pressure.
- To be filtered clean and returns checked to have TSS less than 2 mg/liter before setting packer.
SECTION 20

WELL ABANDONMENT AND SUSPENSION

1. Well Abandonment

- ADCO policy for well abandonment is based on API standard.

- All abandoned wells must be left in such a condition that. Refer to Volume-2, Chapter-3, Non Routine Drilling Operations.
  - Potential leakage of formation fluid to surface has been adequately prevented
  - Hydrocarbon bearing zones are isolated from each others.
  - Fresh water zones are isolated.
  - Fluid migration through the casing and through any uncemented annular space between the casing and the borehole or the next larger casing is prevented.

- Where uncemented casing is in the hole, perforating and squeezing cement must be done to isolate the base of the lowermost fresh water aquifer.

- Casing and cement integrity will be assessed via electric logs.

- Cement plugs across perforations or at top of liner must be verified and tagged.

- The minimum length of any abandonment cement plug is 100 ft.

- The following places must be isolated with cement plugs:
  - Across horizontal hole
  - Across hydrocarbon bearing zones
  - Across the deepest casing shoe
  - Across perforations
  - Across any corroded intervals in the casing string
  - At liner top
  - Across DV's
  - Across water aquifer
  - Below fresh water zones
  - 300 ft below surface
• Final wellhead configuration or land reclamation must be designed in consultation with ADCO Field Production Operations on case by case basis.

• Special abandonment procedure will be conducted in case of behind casing channeling to surface.

• Any Abnormality during the workover job must be risk assessed in consultation with PDD and Fields.

2. Well Suspension

• All wells, which are suspended must be left in such condition that:
  o Potential leakage of formation fluid to surface has been adequately prevented.
  o Isolation between hydrocarbon bearing zones is assured.

• Suspended well must be left with a kill string 100 ft above PBTD landed in tubing hanger.

• Suspended wells must have a suspension tested X-mas tree installed.
SECTION 21

COILED TUBING OPERATIONS

1. Equipment

- On any perforated well where a coiled tubing is to be run in hole, a coiled tubing Shear-Seal BOPs must be employed and installed onto the X-mas tree or wellhead, to give a reasonable assurance that once cut, the coil tubing must drop in hole to regain control of the X-mas tree valves. When Shear-Seal BOPs are employed, all connections between them and the tree or wellhead must be flanged and double valve isolated.

- Coiled tubing Shear seal and Shear ram preventers must be capable of shearing the coiled tubing and any lines within it, at all pressures up to the preventer’s maximum working pressure.

- Remaining coiled tubing fatigue life must be known and monitored prior to and during each job. A coiled tubing replacement philosophy must be in place taking into consideration the coiled tubing operating conditions. The position of all welds and the fluid exposure history must be documented for each reel of tubing.

- The following minimum equipment configuration is required for all coiled tubing operations:
  - Injection Head (10,000 psi).
  - Tandem side-door stripper (10,000 psi).
  - Quad BOP (10,000 psi)
    - Blind / rams
    - Shear rams
    - Slip rams
    - Pipe rams
  - Combi BOP’s (10,000 psi)

- Each equipment item must have working pressure of at least 10,000 psi.

- A kill line must be rigged up on high integrity rig up operations.

- Refer to Coiled Tubing Manual (Production Operation) for more details.
2. **Shear and Pull Test**

A pull test and shear test must be performed while rigging up.

3. **Permitted Load**

For coiled tubing operations the maximum operating loads of 80% of ultimate minimum strength must not be exceeded.
SECTION 22

WIRELINE OPERATIONS

- Wireline operations conducted on a well under pressure must be carried out through appropriate pressure control equipment.

- Wireline operations carried out in open hole with hydrocarbon zones open must be conducted with a means of closing in the well around the cable or a means of clearing the wire from across the BOP stack.

- As a minimum requirement, each of the contracted wire line package must consists of the following main components:
  - Truck mounted wireline unit with either integrated or split crane. All the equipment and related components must meet zone-2 safety regulations. The trucks must be capable to operate in harsh desert terrain.
  - Complete set of surface pressure control equipment that include dual ram, hydraulic / manual control BOP’s, 40 ft. of lubricator sections, hydraulic control stuffing box and minimum of 13” diameter wireline sheaves.
  - Winch drum capable to accommodate either 0.108” or 0.125” wireline drum.

- The wireline reel must be changed after 200 hours of use.

- Lubricator, stuffing box and wireline BOP’s and connection to the wellhead are to be pressure tested to the maximum expected wellhead close in pressure prior with extra safety margin running wireline in hole.

- In high H₂S wells special wireline and tools made from CRA material is to be used.

- For more details, refer to Production Manual.
SECTION 23

WELL SURVEYING AND POSITIONING POLICY

- Directional survey program for all well bores must be designed such that the well bore is known with sufficient accuracy to:
  - Meet the PDD objective of drilling the well
  - Minimize the risk of intersection with any nearby wellbore
  - Drill a relief well
- A Database of well trajectories (Plan and Actual) and all project data must be maintained in a form approved by DD and PDD.
- For deviated wells on clusters, a collision check must be performed on the planned well trajectory. Refer to Wellbore Positioning Manual for details.
- At the planning stage for all wells, surface separation must be 30 ft or greater. Separation below this should be risk assessed and authorized.
- All planned wells must be planned with future wells in mind. Planned wells must have a minimum separation between ellipses of greater than 10 ft. in close proximity situations this can be reduced to 3 ft when approved by Head of Operations.
- All procedures for assessing the tolerable risks of collision, defining minimum well separation and ensuring compliance with such criteria while drilling must be approved by HDO’s and DM.
Table 1-8: Well Surveying Guidelines

<table>
<thead>
<tr>
<th>Item</th>
<th>Hole</th>
<th>Casing</th>
<th>Operation</th>
<th>Applicable to</th>
<th>What to Run</th>
<th>Surveying Frequency</th>
<th>Objective</th>
<th>Remarks</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>26&quot;/22&quot;</td>
<td>18 5/8&quot;</td>
<td>During Drilling 26&quot;/22&quot;</td>
<td>NEB Clusters</td>
<td>MWD survey tool with drilling BHA</td>
<td>Every 1 stand</td>
<td>Avoid risk of intersection with nearby wells</td>
<td>Whenever V-Track BHA is used, Gyro to be run while WOC.</td>
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<tr>
<td>2</td>
<td>26&quot;/22&quot;</td>
<td></td>
<td>After running 18 5/8&quot; casing.</td>
<td>NEB Clusters</td>
<td>North Seeking Gyro Survey on wireline inside 18 5/8&quot; casing</td>
<td>Every 100 ft</td>
<td>Avoid risk of intersection with nearby wells</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>• If Separation Factor with nearby hole &lt;2</td>
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<td></td>
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<tr>
<td></td>
<td></td>
<td></td>
<td>• If 26&quot;/22&quot; hole was drilled without survey</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>3</td>
<td>17 ½/16&quot;</td>
<td>13 3/8&quot;</td>
<td>During Drilling 17 ½&quot; /16&quot; hole</td>
<td>NEB Clusters</td>
<td>MWD survey tool with drilling BHA</td>
<td>Every 1 stand</td>
<td>Avoid risk of intersection with nearby wells</td>
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</tr>
<tr>
<td>4</td>
<td>17 ½/16&quot;</td>
<td></td>
<td>After running 13 3/8&quot; casing.</td>
<td>NEB Clusters</td>
<td>North Seeking Gyro Survey on wireline inside 13 3/8&quot; casing</td>
<td>Every 100 ft</td>
<td>Avoid risk of intersection with nearby wells</td>
<td></td>
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<td></td>
<td></td>
<td></td>
<td>• If Separation Factor with nearby hole &lt;2</td>
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<td></td>
<td>• If 17 ½/16&quot; hole was drilled without survey</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>13 3/8&quot;</td>
<td></td>
<td>After running 13 3/8&quot; casing if the plan is to</td>
<td>SAS</td>
<td>North Seeking Gyro Survey on wireline</td>
<td>Every 100 ft</td>
<td>To Tie in MWD surveys for 12 ¼&quot; hole with 13 3/8&quot; casing shoe</td>
<td>PDD require unusual short displacement of 500 ft at 8 ½&quot; hole landing point. Consequently</td>
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<tr>
<td></td>
<td></td>
<td></td>
<td>drill 12 ¼&quot; hole to Bab Member</td>
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<td></td>
<td></td>
<td></td>
<td>any unrecognized and unplanned departure during the 17 ½&quot; phase will lead to a</td>
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<td>large deviation from the 8 ½&quot; planned profile and will significantly increase</td>
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<td></td>
<td>the required BUR.</td>
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S.G. Rev-0/05  HDO(S/N/E) : Date :  HDO(BU/BB) : Date :  DM : Date :  Page 1-58  Printed on: 02/03/2005
## Surveying

<table>
<thead>
<tr>
<th>Item</th>
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<th>What to Run</th>
<th>Surveying Frequency</th>
<th>Objective</th>
<th>Remarks</th>
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</thead>
<tbody>
<tr>
<td>6</td>
<td>12 ¼&quot;</td>
<td>9 5/8&quot;</td>
<td>During drilling 12 ¼&quot; vertical hole to Bab-Member.</td>
<td>SAS/NEB</td>
<td>MWD survey tool with drilling BHA</td>
<td>Every 1 stand</td>
<td>Control direction and keep the hole within tight tolerance</td>
<td>PDD require unusual short displacement of 500 ft at 8 ½&quot; hole landing point. Consequently any unrecognized and unplanned departure during the 12 ½&quot; phase will lead to a large deviation from the 8 ½&quot; planned profile and will significantly increase the required BUR</td>
</tr>
<tr>
<td>7</td>
<td></td>
<td></td>
<td>During drilling deviated hole.</td>
<td>All Fields</td>
<td>MWD survey tool with drilling BHA</td>
<td>Every 1 stand</td>
<td>To achieve the directional plan</td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>8 ½&quot;</td>
<td>7&quot; liner</td>
<td>setting 9 5/8&quot; whipstock (when hole inclination is less than 10º).</td>
<td>All Fields</td>
<td>North Seeking Gyro Single Shot Survey on wireline inside milling BHA</td>
<td>One shot</td>
<td>Set the whipstock in the correct direction</td>
<td></td>
</tr>
<tr>
<td>9</td>
<td>8 ½&quot;</td>
<td>7&quot; liner</td>
<td>During drilling 8 ½&quot; deviated hole to the landing point.</td>
<td>All Fields</td>
<td>MWD with drilling BHA</td>
<td>As required</td>
<td>Achieve the directional plan and Land 8 ½&quot; hole as per program.</td>
<td></td>
</tr>
<tr>
<td>10</td>
<td></td>
<td></td>
<td>Kick off just below 9 5/8&quot; casing shoe.</td>
<td>All Fields</td>
<td>North Seeking Gyro Steering with drilling BHA</td>
<td>As required</td>
<td>To tie-in the 8 ½ &quot; deviated hole with the 9 5/8&quot; casing.</td>
<td></td>
</tr>
<tr>
<td>11</td>
<td>6&quot;</td>
<td>---</td>
<td>During drilling 6&quot; horizontal section.</td>
<td>All Fields</td>
<td>MWD with drilling BHA</td>
<td>As required</td>
<td>Keep the horizontal hole within tolerance</td>
<td></td>
</tr>
</tbody>
</table>

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DM : 
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</tr>
</thead>
<tbody>
<tr>
<td>12</td>
<td>---</td>
<td>All casing</td>
<td>After running and cementing 7&quot; liner, except when 9.5/8&quot; is set in Bab member&lt;br&gt;Gyro is taken from 9.5/8&quot; shoe to surface.</td>
<td>All Fields</td>
<td>North Seeking Gyro Survey on wireline with Tracker from 7&quot; liner TD to surface.</td>
<td>Every 25 ft (as required)</td>
<td>For PDD data base&lt;br&gt;PDD require Gyro to surface to update fields maps</td>
<td></td>
</tr>
<tr>
<td>13</td>
<td>All open hole</td>
<td>---</td>
<td>Nearby well (25-30) ft affecting MWD readings.</td>
<td>All Fields</td>
<td>North Seeking Gyro Steering survey with drilling BHA.</td>
<td>One shot (repeat as required)</td>
<td>Increase the accuracy of readings and avoid collision.</td>
<td></td>
</tr>
</tbody>
</table>
Chapter 2

DRILLING OPERATIONS GUIDELINES

Revision-0
March 2005
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INTRODUCTION

This chapter of the ADM is intended to provide ADCO Drilling Supervisor and NDC Rig Manager with clear instructions and information for carrying out drilling operations in a controlled, safe, efficient and fully reported manner. It will also serve as a reference document and operational guidelines for the Drilling Engineer while preparing the drilling program.

The step-by-step procedures described in this chapter will be applied to all ADCO’s fields and wells, however it cannot be, an exhaustive guide to programming for all wells. It provides the general and overall guidelines for the execution of drilling and well operations and should be used in conjunction with the “Generic Well Program” and Drilling Program.

It will be the responsibility of the Drilling Team Leader to ensure that all members in his team as well as others with duties relating to Drilling Operations that contained within this chapter are aware of their duties and responsibilities.

To ensure that the chapter contains current information, frequent updating based upon practical and accurate feedback is essential. Therefore, any comments that will improve the content would be welcome. These comments should be submitted in writing to the manual custodians (HDO S/N/E), (HDO B/B) or DTL (Studies) using the proper format.

Drilling Supervisor Responsibilities

ADCO Drilling Supervisor will supervise the drilling operations to ensure that drilling and well operations guidelines contained in this chapter are implemented. He is the only person authorized to give instructions to the Drilling Contractor and it is his duty to ensure that ADCO policies, practices and instructions are completely understood and carried out.
SECTION 1

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.

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](image-url)
SECTION 2

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 piling 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.

![Diagram of Drilling 36" Hole through 40" Riser](image)
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.

![Diagram showing 40” Conductor pipe while drilling 36” hole](image)

- 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>
<thead>
<tr>
<th>Option 1</th>
<th>Option 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Size</td>
<td>Description</td>
</tr>
<tr>
<td>36”</td>
<td>Bit</td>
</tr>
<tr>
<td>36”</td>
<td>Near bit Stab</td>
</tr>
<tr>
<td>9.75”</td>
<td>Drill collar</td>
</tr>
<tr>
<td>9.75”</td>
<td>Crossover</td>
</tr>
<tr>
<td>8.25”</td>
<td>Drill Collar</td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
</tbody>
</table>

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

- 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.
- 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](image)

• 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.

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.

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 ¾” 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 2-13: 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>
<thead>
<tr>
<th>Characteristics</th>
<th>40” Casing</th>
</tr>
</thead>
<tbody>
<tr>
<td>Body OD (in)</td>
<td>40</td>
</tr>
<tr>
<td>Grade</td>
<td>X-52</td>
</tr>
<tr>
<td>Weight (lb/ft)</td>
<td>417</td>
</tr>
<tr>
<td>Connection</td>
<td>Welded</td>
</tr>
<tr>
<td>Min. ID (In)</td>
<td>38</td>
</tr>
<tr>
<td>Capacity (Bbls/ft)</td>
<td>1.403</td>
</tr>
</tbody>
</table>

11.2 30” Conductor Pipe

Mesc No. 0401805299

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

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

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

11.4 Other Equipment

Table 2-6: 30” Conductor pipe and accessories

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

12. Waste Management

<table>
<thead>
<tr>
<th>Hole Size</th>
<th>Mud Salinity</th>
<th>Rental Equipment</th>
<th>Mud Handling</th>
<th>Cuttings Handling</th>
</tr>
</thead>
<tbody>
<tr>
<td>36”</td>
<td>Water Base Mud</td>
<td>Tanks 4</td>
<td>NO DUMPING Excess mud to be transported to injection disposal well.</td>
<td>Cuttings to be piled on location and to be used to bund the location.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Centrifuge 1</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

S.G. Rev-0/05 HDO(S/N/E) : Date : HDO(BU/BB) : Date : DM : Date : Page 2-21

Printed on: 02/03/2005
The setting depth for 18 ⅞" 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 ⅞" 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 ⅞" casing in each field:
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 nipping 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](image1)

![Figure 2-16: Drilling 26" Hole through 29 ½" Diverter](image2)
• The following 26” drilling assemblies will be used to drill out this section.

Table 2-7: Recommended BHA for 26” Hole

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

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

2) KCL/XC-Polymer Mud Properties:

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Density, pcf</td>
<td>72 - 75</td>
</tr>
<tr>
<td>Viscosity, sec/qt</td>
<td>45 – 55</td>
</tr>
<tr>
<td>YP, #/100 ft²</td>
<td>18 – 25</td>
</tr>
<tr>
<td>PV, cps</td>
<td>ALAP / 7 – 10</td>
</tr>
<tr>
<td>10 sec Gel, #/100 ft²</td>
<td>3 – 6</td>
</tr>
<tr>
<td>10 min Gel, #/100 ft²</td>
<td>8 – 12</td>
</tr>
<tr>
<td>API FL, cc/30 min.</td>
<td>10 – 12</td>
</tr>
<tr>
<td>Drill Solids Content, %</td>
<td>&lt; 6 (max.) LGS</td>
</tr>
<tr>
<td>PH</td>
<td>8.5 – 9.5</td>
</tr>
</tbody>
</table>

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 ¾” 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 ¾” x 30” 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.
  o Before setting heavy duty clamp, run two Macaroni pipe strings at different sides of 18 ¾” x 30” annulus to top of cement, or to a maximum depth of 200 ft.
  o Mix and pump 118 pcf cement slurry through the Macaroni pipe until annulus is filled with cement.
  o 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)
  o Wait on cement 6-8 hours.
  o Lower 2” pipe few feet down the annulus.
  o 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.
  o Connect cementing line to on side of the Casing Head outlet
  o 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.
  o Watch pressure carefully; ensure pump pressure do not exceeds 400 psi surface pressure to avoid casing collapse.
  o 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).
  o Wait on cement 6-8 hours.
  o 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
  
  Or

• 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 ⅜” Casing Landed on 30” landing ring

Figure 2-19: Mud Riser or Diverter removed after landing 18 ¾” 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

<table>
<thead>
<tr>
<th>Potential Hazard</th>
<th>How to mitigate</th>
</tr>
</thead>
</table>
| **Severe water flow or loss** | • **Understanding the Miocene and Dammam formation:**
  o 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:**
    o Review offset wells prior to spudding the well
    o In case of sudden losses, try to continue drilling with controlled GPM and ROP, circulate at least bottom up prior to POH.
    o To avoid losses into Dammam, circulate and clean hole at 50’ above top Dammam and displace with fresh mud.
    o Be prepared to fill hole down annulus at maximum possible pumping rate.
    o 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** | • 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. |
| **Losses followed by sand caving** | • 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. |
| **Tight hole** | • 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. |

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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**

<table>
<thead>
<tr>
<th>13 ¾” Setting Depth</th>
<th>18 ⅛” Mud Riser</th>
<th>21 ¼” Diverter</th>
<th>21 ¼” Annular Preventer</th>
</tr>
</thead>
<tbody>
<tr>
<td>13 ¾” casing set at Dam.</td>
<td>Yes</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>13 ¾” casing set at Rus</td>
<td>Yes</td>
<td>Only if flow was experienced from Dammam in offset well</td>
<td>No</td>
</tr>
<tr>
<td>13 ¾” casing set at Fiqa</td>
<td>No</td>
<td>No</td>
<td>Yes</td>
</tr>
</tbody>
</table>

11.1 Mud Riser 18 ⅛”

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
  - 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.
  - Make up the 21.26” adapter assembly
  - Running tool
- Lower the assembly, land on casing head and secure using the Hold down screws.
- Nipple up 21 ¾” - 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.
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.

Figure 2-20: Diverter Stack for Drilling 17.1/2" Hole
• 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>
<thead>
<tr>
<th>S.N.</th>
<th>Description</th>
<th>Grade</th>
<th>Wt lb/ft</th>
<th>Thread</th>
<th>MESC No.</th>
<th>Store</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Casing (R-3)</td>
<td>K-55</td>
<td>87.5</td>
<td>BTC</td>
<td>04.20.03.605.9</td>
<td>2</td>
</tr>
<tr>
<td>2</td>
<td>Stab-in Collar</td>
<td>K-55</td>
<td>87.5</td>
<td>BTC</td>
<td>05.14.26.032.9</td>
<td>2</td>
</tr>
<tr>
<td>3</td>
<td>Stab-in Shoe</td>
<td>K-55</td>
<td>87.5</td>
<td>BTC</td>
<td>05.14.17.044.9</td>
<td>2</td>
</tr>
<tr>
<td>4</td>
<td>O.H. Centraliser</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>05.17.25.912.9</td>
<td>2</td>
</tr>
<tr>
<td>5</td>
<td>Stop Collar</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>05.17.55.148.1</td>
<td>2</td>
</tr>
<tr>
<td>6</td>
<td>Casing dope</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>87.47.25.07.09</td>
<td>2</td>
</tr>
<tr>
<td>7</td>
<td>Thread compound</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>87.42.47.24.09</td>
<td>2</td>
</tr>
</tbody>
</table>

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 must be corrosion coated.

Dimensions, mechanical properties and make up torque of the 18 3/8” casing:

<table>
<thead>
<tr>
<th>Option</th>
<th>18 3/8” Casing</th>
</tr>
</thead>
<tbody>
<tr>
<td>Body OD (in)</td>
<td>18 %</td>
</tr>
<tr>
<td>Grade</td>
<td>K-55</td>
</tr>
<tr>
<td>Weight with collar (lb/ft)</td>
<td>87.5</td>
</tr>
<tr>
<td>Connection</td>
<td>Buttress</td>
</tr>
<tr>
<td>Min. ID (in)</td>
<td>17.755</td>
</tr>
<tr>
<td>Drift diameter (in)</td>
<td>17.567</td>
</tr>
<tr>
<td>OD of coupling (in)</td>
<td>19.625</td>
</tr>
<tr>
<td>Capacity (bbls/ft)</td>
<td>0.3062</td>
</tr>
<tr>
<td>Body yield strength (klbs)</td>
<td>1367</td>
</tr>
<tr>
<td>Coupling yield strength BTC (klbs)</td>
<td>1427</td>
</tr>
<tr>
<td>Collapse pressure (psi)</td>
<td>630</td>
</tr>
<tr>
<td>Burst pressure (psi)</td>
<td>2250</td>
</tr>
<tr>
<td>Make up torque optimum</td>
<td>Triangle level</td>
</tr>
</tbody>
</table>
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>
<thead>
<tr>
<th>Hole Size</th>
<th>Mud Salinity</th>
<th>Rental Equipment</th>
<th>Mud Handling</th>
<th>Cuttings Handling</th>
</tr>
</thead>
<tbody>
<tr>
<td>26”</td>
<td>Water Base Mud</td>
<td>Tanks 4</td>
<td>NO DUMPING</td>
<td>Cuttings to be piled on location and to be used to bund the location.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Centrifuge 1</td>
<td>Excess mud to be transported to injection disposal well.</td>
<td></td>
</tr>
</tbody>
</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.
SECTION 4

17 ½” HOLE FOR 13 ¾” CASING

1. Purpose

17 ½” hole in ADCO is drilled to run 13 ¾” 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 ¾” casing is typically run to:

- Case-off part of Miocene formation prior to drilling Dammam formation.
- Case-off Dammam formation prior to drilling UER and Simsima formation.
- Case-off UER and Simsima prior to drilling Nahr Umr Shale and pay zones.

2. Applications

13 ¾” casing setting depths depends on the overall well casing design and well type, see table bellow.

Table 2-14: 13 ¾” Casing Setting Formation

<table>
<thead>
<tr>
<th>Well Type</th>
<th>Casing Setting Formation</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Dammam</td>
</tr>
<tr>
<td>Gas producer/injector and WAG</td>
<td>X</td>
</tr>
<tr>
<td>Oil producer</td>
<td>√</td>
</tr>
<tr>
<td>Water injector</td>
<td>√</td>
</tr>
<tr>
<td>Water supply</td>
<td>√</td>
</tr>
<tr>
<td>Surface</td>
<td>BAB</td>
</tr>
<tr>
<td>---------</td>
<td>-----</td>
</tr>
<tr>
<td>Surface Sand</td>
<td>30° C.P. 3 Jts</td>
</tr>
<tr>
<td>Miocene</td>
<td>18 ½&quot; Csg</td>
</tr>
<tr>
<td>Dammam</td>
<td>TD</td>
</tr>
<tr>
<td>RUS</td>
<td>TD</td>
</tr>
<tr>
<td>Fiqqa</td>
<td>TD</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Surface</th>
<th>SAHIL</th>
<th>DHABBIYA</th>
<th>SHANAYEL</th>
<th>RUMAITHA</th>
<th>SHAH</th>
</tr>
</thead>
<tbody>
<tr>
<td>Surface Sand</td>
<td>30° C.P. 3 Jts</td>
<td>30° C.P. 1 Jt</td>
<td>30° C.P. 3 Jts</td>
<td>30° C.P. 4 Jts</td>
<td>30° C.P. 3 Jts</td>
</tr>
<tr>
<td>Miocene</td>
<td>18 ½&quot; Csg</td>
<td>18 ½&quot; Csg</td>
<td>18 ½&quot; Csg</td>
<td>18 ½&quot; Csg</td>
<td>18 ½&quot; Csg</td>
</tr>
<tr>
<td>Dammam</td>
<td>TD</td>
<td>18 ½&quot; Csg</td>
<td>18 ½&quot; Csg</td>
<td>18 ½&quot; Csg</td>
<td>TD</td>
</tr>
<tr>
<td>RUS</td>
<td>TD</td>
<td>TD</td>
<td>Deviated hole</td>
<td>TD</td>
<td>TD</td>
</tr>
<tr>
<td>Fiqqa</td>
<td>TD</td>
<td>TD</td>
<td>TD</td>
<td>TD</td>
<td>TD</td>
</tr>
</tbody>
</table>

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 ¾” 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 ¾” 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

<table>
<thead>
<tr>
<th>Option 1</th>
<th>Option 2</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Rotary drilling</strong></td>
<td><strong>Motor drilling</strong></td>
</tr>
<tr>
<td><strong>Size</strong></td>
<td><strong>Description</strong></td>
</tr>
<tr>
<td>17.5”</td>
<td>Bit</td>
</tr>
<tr>
<td>10.5”</td>
<td>Shock sub</td>
</tr>
<tr>
<td>9.75”</td>
<td>Drill collar</td>
</tr>
<tr>
<td>17.5”</td>
<td>String stabilizer</td>
</tr>
<tr>
<td>9.75”</td>
<td>Drill collar</td>
</tr>
<tr>
<td>17.5”</td>
<td>String stabilizer</td>
</tr>
<tr>
<td>9.75”</td>
<td>Drill collar</td>
</tr>
<tr>
<td>9.75”</td>
<td>Cross over</td>
</tr>
<tr>
<td>8.25”</td>
<td>Drill collar</td>
</tr>
<tr>
<td>8”</td>
<td>Drilling Jar</td>
</tr>
<tr>
<td>8.25”</td>
<td>Drill collar</td>
</tr>
<tr>
<td>8.25”</td>
<td>Cross over</td>
</tr>
<tr>
<td>5”</td>
<td>HWDP</td>
</tr>
</tbody>
</table>

4.2 Drilling Guidelines

- Clean out 18 ¾” casing, drill floats.
- Drills first 100’ below 18 ¾” shoe with reduced parameters (WOB, RPM and flow rate) until the stabilizers/roller reamers are below 18 ¾” shoe.
- Avoid washing out the unconsolidated formation around 18 ¾” 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 to 10 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

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Density, pcf</td>
<td>58 - 60 or as hole conditions dictates</td>
</tr>
<tr>
<td>Viscosity, sec/qt</td>
<td>40 – 50</td>
</tr>
<tr>
<td>YP, #/100 ft²</td>
<td>16 – 20</td>
</tr>
<tr>
<td>PV, cps</td>
<td>ALAP / 7 – 10</td>
</tr>
<tr>
<td>10 sec Gel, #/100 ft²</td>
<td>3 – 6</td>
</tr>
<tr>
<td>10 min Gel, #/100 ft²</td>
<td>8 – 12</td>
</tr>
<tr>
<td>API FL, cc/30 min.</td>
<td>N/C to 15 – 20 prior to running CSG</td>
</tr>
</tbody>
</table>
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 3/8” Casing

• Make up float shoe to the 1st joint of 13 3/8" 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:

- 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 values 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 ¾” 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 ¾” 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 ¾” Casing

13 ¾” 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 ¾” 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 ¾” 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 ¾” Casing head load shoulder

- Proceed to cementing 13 ¾” casing.
• Lay down landing joint
• Nipple down annular preventer / diverter, Figure 2-26.

**Note:**
If 17 ½” hole is drilled through 18 5/8” riser, nipple down riser before running 13 ¾” casing (mandrel casing hanger OD = 20.116” and 18 5/8” casing ID = 17.755”)

![Diagram](image-url)

Figure 2-26: 13 ¾” Casing landed on CH Mandrel

### 8.2 Landing 13 ¾” Casing on Heavy Duty Clamp

• After drilling 17 ½” hole; run 13 ¾” 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 ¾” casing.
• Raise 18 ¾” riser, annular preventer or diverter and hang in substructure, cut remaining 18 ¾” 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.

![Heavy Duty Clamp for Landing 13 ⅜” Casing](image)

**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 ¾” 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 ¾” x 18 ½” 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 ¾” Cement Slurry Specifications

Table 2-17: 13 ¾” Casing Cement Slurry Specifications

<table>
<thead>
<tr>
<th>Casing Setting Formation</th>
<th>Spacer Ahead</th>
<th>Slurry Type</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Lead Slurry</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Light weight cement slurry (84/86 PCF)</td>
</tr>
<tr>
<td>Dammam</td>
<td>30 Bbls Location Water, 40 Bbls Mix Water</td>
<td>Light weight cement slurry (84/86 PCF)</td>
</tr>
<tr>
<td>Rus</td>
<td>30 Bbls Location Water, 40 Bbls Mix Water</td>
<td>Light weight cement slurry (84/86 PCF)</td>
</tr>
<tr>
<td>Fiqa</td>
<td>30 Bbls Location Water, 40 Bbls Mix Water</td>
<td>Light weight cement slurry (75/80 PCF or 64/70 PCF)</td>
</tr>
</tbody>
</table>
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
  - Before setting heavy duty clamp; run two Macaroni pipe strings at different sides of 13 ⅜"x18 ⅜" annulus to top of cement, or to a maximum depth of 200 ft.
  - Mix and pump 125 pcf cement slurry through the macaroni pipes until annulus is filled with cement.

- Annulus above top of cement is empty
  - Lower 2" line few feet down the annulus.
  - Fill cement slurry at lowest rate.
  - 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 ⅜" 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.
  - Connect cementing line to the side of the Casing Head outlet. Figure 2-28.
  - 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.
  - Ensure that pump pressure do not exceed 500 psi to avoid collapse of the 13 ⅜" casing.

- Annulus above top of cement is empty.
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 ¾” Casing in case of empty annulus

10. Potential Drilling Hazards

<table>
<thead>
<tr>
<th>Potential Hazard</th>
<th>How to mitigate</th>
</tr>
</thead>
</table>
| 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** |
<table>
<thead>
<tr>
<th>Potential Hazard</th>
<th>How to mitigate</th>
</tr>
</thead>
<tbody>
<tr>
<td>into top Dammam</td>
<td>for each problem that is likely to happen.</td>
</tr>
<tr>
<td></td>
<td>• Don’t apply more than 30,000 lb over pull, if needed, run back to bottom and circulate while rotating at high speed.</td>
</tr>
<tr>
<td>Stuck casing due to hole cleaning, hole geometry, loss/flow or tight hole</td>
<td>Stick to the BHA specified in the drilling program.</td>
</tr>
<tr>
<td></td>
<td>• Avoid creating ledges by easing bit in harder formation and reaming transition between formations.</td>
</tr>
<tr>
<td></td>
<td>• Watch casing string weight, understand and monitor casing drag up and down.</td>
</tr>
<tr>
<td></td>
<td>• Avoid thick mud cake by controlling fluid loss and solids.</td>
</tr>
<tr>
<td></td>
<td>• Circulate hole clean prior to POH for casing</td>
</tr>
<tr>
<td></td>
<td>• Survey check with Totco at bottom.</td>
</tr>
<tr>
<td>Damage of bit cutting Structure in Rus</td>
<td>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).</td>
</tr>
<tr>
<td>Bit Balling</td>
<td>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.</td>
</tr>
<tr>
<td></td>
<td>In 17 ½” section, balling is likely to be either global or teeth balling in mill tooth bit or both.</td>
</tr>
<tr>
<td></td>
<td>All types of balling can be reduced by having a sufficiently inhibitive mud.</td>
</tr>
<tr>
<td></td>
<td>Global Balling risk will be reduced by consistently high flow rates, and good hole cleaning.</td>
</tr>
<tr>
<td></td>
<td>Teeth balling risk exists in Dammam Basal Shale, and UER Basal Shale.</td>
</tr>
<tr>
<td></td>
<td>• Ensure of pumping at high flow rates, and sufficient HSI ( &gt;2 ).</td>
</tr>
<tr>
<td></td>
<td>• 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).</td>
</tr>
<tr>
<td></td>
<td>• Avoid excessive WOB while drilling through these formations.</td>
</tr>
<tr>
<td></td>
<td><strong>Actions once balling has been detected:</strong></td>
</tr>
<tr>
<td></td>
<td>• Bits can be cleared if balling is detected early enough and actions taken.</td>
</tr>
<tr>
<td></td>
<td>• Reduce WOB when ROP drops, pick up bit off bottom as quickly as possible and increase flow rate.</td>
</tr>
<tr>
<td></td>
<td>• Spin bit off bottom with high RPM and high flow rate for 5 minutes</td>
</tr>
<tr>
<td></td>
<td>• Resume drilling with very low weight</td>
</tr>
<tr>
<td></td>
<td>• Prepare to pump pills (high concentration glycol pill (15-20%) and fresh water pill), leave to soak and try to dissolve/loosen balled material</td>
</tr>
<tr>
<td></td>
<td>Prepare to trip if these actions are not successful and choose more optimum, bit, hydraulics nozzling arrangement or mud system</td>
</tr>
</tbody>
</table>
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 ¾” CHH through rotary table

Figure 2-30: 13.5/8” Thread Type CHH after landing 13 ¾” casing
12. **Blowout Prevention**

BOP stacks in ADCO are classified into 4 categories:

- (I) (Ann 5000 psi + 3 Rams 10000 psi equipped with 35% H₂S elastomers).
- (II) (Ann 5000 psi + 3 Rams 5000 psi equipped with 35% H₂S elastomers).
- (III) (Ann 5000 psi + 2 Rams 5000 psi equipped with 35% H₂S elastomers).
- (IV) (Ann 5000 psi + 2 Rams equipped with 5% H₂S elastomers).

See Figure 2-32 and Figure 2-33

Refer to the Chapter-3, “well Control” of this volume for selecting the proper BOP’s stack minimum requirement.

---

**Figure 2-31:** 13 ¾” Slip on Lock CHH after landing 13 ¾” casing

---

**Figure 2-31:**
Figure 2-32: Class (I) & (II) BOP Stack
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 ⅜" - 5000 psi Casing Head Housing (Plan for installing the rotating head at later stage by adjusting the length of spacer).
- Nipple up 13 ⅜" 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 ⅜" 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

<table>
<thead>
<tr>
<th>S.N.</th>
<th>Description</th>
<th>Grade</th>
<th>Wt lb/ft</th>
<th>Thread</th>
<th>MESC No.</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Casing, R3</td>
<td>K-55</td>
<td>68</td>
<td>BTC</td>
<td>04.08.03.520.1</td>
</tr>
<tr>
<td>3</td>
<td>Float Shoe</td>
<td>K-55</td>
<td>61 - 72</td>
<td>BTC</td>
<td>05.14.17.622.9</td>
</tr>
<tr>
<td>4</td>
<td>O.H. Centralizer</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>05.17.25.160.9</td>
</tr>
<tr>
<td>5</td>
<td>Positive Centralizer</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>05.17.30.168.9</td>
</tr>
<tr>
<td>6</td>
<td>Stop Collar</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>05.17.55.125.1</td>
</tr>
<tr>
<td>7</td>
<td>Casing dope</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>87.47.25.07.09</td>
</tr>
<tr>
<td>8</td>
<td>Thread compound</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>87.42.47.24.09</td>
</tr>
</tbody>
</table>

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

Table 2-20: 13 ⅜” Casing properties

<table>
<thead>
<tr>
<th>Description</th>
<th>ADCO Wells</th>
<th>ADNOC Wells</th>
</tr>
</thead>
<tbody>
<tr>
<td>Body OD (Inch)</td>
<td>13 ⅜”</td>
<td>13 ⅜”</td>
</tr>
<tr>
<td>Grade</td>
<td>K-55</td>
<td>L-80</td>
</tr>
<tr>
<td>Weight with collar (lb/ft)</td>
<td>68</td>
<td>68</td>
</tr>
<tr>
<td>Connection</td>
<td>Buttress</td>
<td>Premium</td>
</tr>
</tbody>
</table>
### 13.2 Wellhead

Equipment required for the 13 ¾” wellhead is:

<table>
<thead>
<tr>
<th>13 ¾” Casing Landing Method</th>
<th>Heavy Duty Clamp</th>
<th>Casing Hanger Mandrel</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wellhead equipment required</td>
<td>CHH 13 ¾” Buttress x 13 ¾” 5M with two 2.1/16” stdd outlets (either threaded or slip on lock type)</td>
<td>CHH 13 ¾” Buttress x 13 ¾” 5M with two 2.1/16” stdd outlets (either Threaded or Slip On Lock type)</td>
</tr>
<tr>
<td></td>
<td>2.1/16” Gate valve</td>
<td>2.1/16” Gate valve</td>
</tr>
<tr>
<td></td>
<td>2” Bull Plug</td>
<td>2” Bull Plug</td>
</tr>
<tr>
<td></td>
<td>Gauge</td>
<td>Gauge</td>
</tr>
<tr>
<td></td>
<td>Pup joint 13 ¾” (pin x pin)</td>
<td>Pup joint 13 ¾” (pin x pin)</td>
</tr>
</tbody>
</table>

### 14. Waste Management

- 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.
SECTION 5

12 ¼” HOLE FOR 9 5⁄8” CASING

The 9 5⁄8” 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 5⁄8” casing in Shilaif when usable TVD is insufficient to drill the 8 ½” build section. 9 5⁄8” 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 5⁄8” casing just above the production/injection zones when usable TVD is sufficient to drill the 8 ½” build section, 9 5⁄8” 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 5⁄8” casing across the top reservoir 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 ⅜" Phase

<table>
<thead>
<tr>
<th>Surface (G.L)</th>
<th>BAB</th>
<th>BU-HASA</th>
<th>ASAB</th>
</tr>
</thead>
<tbody>
<tr>
<td>Surface Sand</td>
<td>30° C.P.</td>
<td>30° C.P.</td>
<td>30° C.P.</td>
</tr>
<tr>
<td>Miocene</td>
<td>13 ⅜&quot; Csg</td>
<td>13 ⅜&quot; Csg</td>
<td>13 ⅜&quot; Csg</td>
</tr>
<tr>
<td>Dammam</td>
<td>30° C.P. 3 Jts</td>
<td>18 ⅜&quot; Csg</td>
<td>18 ⅜&quot; Csg</td>
</tr>
<tr>
<td>RUS</td>
<td>13 ⅜&quot; Csg</td>
<td>13 ⅜&quot; Csg</td>
<td>13 ⅜&quot; Csg</td>
</tr>
<tr>
<td>Simsima</td>
<td>13 ⅜&quot; Csg</td>
<td>13 ⅜&quot; Csg</td>
<td>13 ⅜&quot; Csg</td>
</tr>
<tr>
<td>Fiqqa</td>
<td>TD</td>
<td>TD</td>
<td>TD</td>
</tr>
<tr>
<td>Shelaif</td>
<td>TD</td>
<td>TD</td>
<td>TD</td>
</tr>
<tr>
<td>Nahr Umr</td>
<td>TD</td>
<td>TD</td>
<td>TD</td>
</tr>
<tr>
<td>B M./Shuaiba</td>
<td>TD</td>
<td>TD</td>
<td>TD</td>
</tr>
<tr>
<td>Thammam</td>
<td>TD</td>
<td>TD</td>
<td>TD</td>
</tr>
</tbody>
</table>

S.G. Rev-05 | HDO(S/N/E) Date | HDO(BU/BB) Date | DM Date | Page 2-66
Printed on: 02/03/2005
<table>
<thead>
<tr>
<th>Surface (G.L.)</th>
<th>SAHIL</th>
<th>DABBIYA</th>
<th>SHAH</th>
<th>SHANAYEL</th>
<th>RUMAITHA</th>
</tr>
</thead>
<tbody>
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<td>Surface Sand</td>
<td>30° C.P. 3 Jts</td>
<td>30° C.P. 3 Jts</td>
<td>30° C.P. 3 Jts</td>
<td>30° C.P. 4 Jts</td>
<td>30° C.P. 4 Jts</td>
</tr>
<tr>
<td>Miocene</td>
<td>18 ½” Csg</td>
<td>18 ½” Csg</td>
<td>18 ½” Csg</td>
<td>18 ½” Csg</td>
<td>18 ½” Csg</td>
</tr>
<tr>
<td>Dammam</td>
<td>18 ½” Csg</td>
<td>18 ½” Csg</td>
<td>18 ½” Csg</td>
<td>18 ½” Csg</td>
<td>18 ½” Csg</td>
</tr>
<tr>
<td>RUS</td>
<td>13 ¾” Csg</td>
<td>13 ¾” Csg</td>
<td>13 ¾” Csg</td>
<td>13 ¾” Csg</td>
<td>13 ¾” Csg</td>
</tr>
<tr>
<td>Simsima</td>
<td>13 ¾” Csg</td>
<td>13 ¾” Csg</td>
<td>13 ¾” Csg</td>
<td>13 ¾” Csg</td>
<td>13 ¾” Csg</td>
</tr>
<tr>
<td>Fiqa</td>
<td>13 ¾” Csg</td>
<td>13 ¾” Csg</td>
<td>13 ¾” Csg</td>
<td>13 ¾” Csg</td>
<td>13 ¾” Csg</td>
</tr>
<tr>
<td>Shelaif</td>
<td>TD</td>
<td>TD</td>
<td>TD</td>
<td>TD</td>
<td>TD</td>
</tr>
<tr>
<td>Nahr Umr</td>
<td>TD</td>
<td>TD</td>
<td>TD</td>
<td>TD</td>
<td>TD</td>
</tr>
<tr>
<td>B M./Shuaiba</td>
<td>TD</td>
<td>TD</td>
<td>TD</td>
<td>TD</td>
<td>TD</td>
</tr>
<tr>
<td>Thammam</td>
<td>TD</td>
<td>TD</td>
<td>TD</td>
<td>TD</td>
<td>TD</td>
</tr>
</tbody>
</table>
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 ¾” casing is set into Rus or Fiqa).
- Continue drilling 12 ¼” hole to 9 ⅝” casing point.
- Proceed as follows if 13 ¾” casing is set into Rus or shallower, and aerated drilling technique is required to drill UER and Simsima:
  - Nipple up rotating head on top of 13 ⅛” BOP.
  - Run in hole with 12 ¼” bit.
  - 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 ¾” 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, Ruwaydah, 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 ¾” 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 5º/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 ½” hole

<table>
<thead>
<tr>
<th>Size</th>
<th>Description</th>
<th>No.</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>12 ¼”</td>
<td>Motor insert bit</td>
<td>1</td>
<td>Motor Insert bit, 4-3-5, 5-1-7, or 6 bladed 16mm-13mm PDC, (centre jet, mini extended nozzles on insert)</td>
</tr>
<tr>
<td>9 ¾”</td>
<td>Motor</td>
<td>1</td>
<td>(fitted with 12 1/8” sleeve stab)</td>
</tr>
<tr>
<td>12 ¼”</td>
<td>Roller Reamer</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>8”</td>
<td>MWD</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>8”</td>
<td>Oriented sub</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>8”</td>
<td>N.M.D.C</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>12 ¼”</td>
<td>Roller Reamer</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>8”</td>
<td>N.M.D.C</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>8.1/4”</td>
<td>DC</td>
<td>12</td>
<td></td>
</tr>
<tr>
<td>8”</td>
<td>Drilling Jar</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>8.1/4”</td>
<td>D.C</td>
<td>3</td>
<td></td>
</tr>
<tr>
<td>7”</td>
<td>D.C</td>
<td>3</td>
<td></td>
</tr>
<tr>
<td>X Over</td>
<td>X Over Sub</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>5”</td>
<td>HWDP</td>
<td>9</td>
<td></td>
</tr>
</tbody>
</table>

Option 2: Motor drilling – Directional with flex joint

Table 2-23: Recommended Directional BHA for drilling 12 ½” with flex joint

<table>
<thead>
<tr>
<th>Size</th>
<th>Description</th>
<th>No.</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>12 ¼”</td>
<td>Motor insert bit</td>
<td>1</td>
<td>Motor Insert bit, 4-3-5, 5-1-7, or 6 bladed 16mm-13mm PDC, (centre jet, mini extended nozzles on insert)</td>
</tr>
<tr>
<td>9 ¾”</td>
<td>Motor</td>
<td>1</td>
<td>(fitted with 12 1/8” sleeve stab)</td>
</tr>
<tr>
<td>8.1/4”</td>
<td>Flex Joint</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>8”</td>
<td>MWD (Power Pulse)</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>8”</td>
<td>N.M.D.C</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>12 ¼”</td>
<td>Roller Reamer</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>8”</td>
<td>N.M.D.C</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>8.1/4”</td>
<td>DC</td>
<td>12</td>
<td></td>
</tr>
<tr>
<td>8”</td>
<td>Drilling Jar</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>8.1/4”</td>
<td>D.C</td>
<td>2</td>
<td></td>
</tr>
<tr>
<td>7”</td>
<td>D.C</td>
<td>3</td>
<td></td>
</tr>
<tr>
<td>X Over</td>
<td>X Over Sub</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>5”</td>
<td>HWDP</td>
<td>9</td>
<td></td>
</tr>
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</table>
### Option 3: Motor drilling – Vertical

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

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

### Option 4: Motor drilling – vertical

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

<table>
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<tr>
<th>Size</th>
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<th>No.</th>
<th>Comments</th>
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</thead>
<tbody>
<tr>
<td>12 ¼&quot;</td>
<td>Insert bit or PDC</td>
<td>1</td>
<td>Motor insert bit, 4-3-5, 5-1-7 or 5 blades 16 mm – 13 mm PDC, (center jet, mini extended nozzles on insert)</td>
</tr>
<tr>
<td>9 5/8&quot;</td>
<td>Motor</td>
<td>1</td>
<td>Fitted with 12.1/8&quot; sleeve stab</td>
</tr>
<tr>
<td>9 1/2&quot;</td>
<td>Float sub</td>
<td></td>
<td>Totco ring</td>
</tr>
<tr>
<td>12 ¼&quot;</td>
<td>Roller Reamer</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>8.1/4&quot;</td>
<td>DC</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>12 ¼&quot;</td>
<td>Int. Blade Stab</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>8.1/4&quot;</td>
<td>DC</td>
<td>12</td>
<td></td>
</tr>
<tr>
<td>8&quot;</td>
<td>Drilling Jar</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>8.1/4&quot;</td>
<td>DC</td>
<td>2</td>
<td></td>
</tr>
<tr>
<td>7&quot;</td>
<td>D.C</td>
<td>3</td>
<td></td>
</tr>
<tr>
<td>X Over</td>
<td>X Over sub</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>5&quot;</td>
<td>5&quot; HWDP</td>
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</table>

### Option 5: Rotary drilling – Pendulum

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

<table>
<thead>
<tr>
<th>Size</th>
<th>Description</th>
<th>No.</th>
<th>Comments</th>
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</thead>
<tbody>
<tr>
<td>12 ¼&quot;</td>
<td>Rock bit or PDC</td>
<td>1</td>
<td>Bit, 4-3-5 or 5-1-7</td>
</tr>
<tr>
<td>Bit Sub</td>
<td>Bit Sub</td>
<td>1</td>
<td>Equipped with float sub and Totco ring</td>
</tr>
<tr>
<td>8.1/4&quot;</td>
<td>DC</td>
<td>2</td>
<td></td>
</tr>
<tr>
<td>12.1/8&quot;</td>
<td>S. Stab</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>8.1/4&quot;</td>
<td>DC</td>
<td>16</td>
<td></td>
</tr>
<tr>
<td>8&quot;</td>
<td>Drilling Jar</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>8.1/4&quot;</td>
<td>DC</td>
<td>3</td>
<td></td>
</tr>
<tr>
<td>8.1/4&quot;</td>
<td>X Over</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>7&quot;</td>
<td>DC</td>
<td>3</td>
<td></td>
</tr>
<tr>
<td>X Over</td>
<td>X Over Sub</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>5&quot;</td>
<td>HWDP</td>
<td>9</td>
<td></td>
</tr>
</tbody>
</table>
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

<table>
<thead>
<tr>
<th>Survey and Logging Instrument type</th>
<th>Survey Frequency</th>
<th>Remark</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gyro In 13 ¾” casing. MWD/PWD + (CDR)</td>
<td>Directional surveys every stand, reducing the frequency as applicable. Continuous PWD MWD/PWD + (CDR)</td>
<td>Contingency: Multishot at TD or on trips include NMDC/totco ring</td>
</tr>
</tbody>
</table>

- 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

<table>
<thead>
<tr>
<th>Formation</th>
<th>Directional Issues</th>
</tr>
</thead>
<tbody>
<tr>
<td>Shilaif</td>
<td>• 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.</td>
</tr>
<tr>
<td>Mauddud</td>
<td>No major issues.</td>
</tr>
<tr>
<td>Nahr Umr</td>
<td>• 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</td>
</tr>
</tbody>
</table>

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.

  o Refer to hole cleaning section in Chapter 4, Drilling Optimization of this volume.

  o 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 5/8” 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:
  o 1 OH Cent. 5 ft above shoe over stop collar.
  o 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 ¾” 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 ¾” 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 ¾” Casing

9 ¾” 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 ¾” 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 ¾” Casing Cement Slurry**

<table>
<thead>
<tr>
<th>Casing Setting Formation</th>
<th>Spacer Ahead</th>
<th>Lead Slurry</th>
<th>Tail Slurry</th>
</tr>
</thead>
<tbody>
<tr>
<td>Shilaif Bab Member</td>
<td>40 Bbls Location Water and 30 Bbls Mix Water</td>
<td>Light weight cement slurry</td>
<td>Class G cement slurry (118 pcf)</td>
</tr>
<tr>
<td>Shuaiba / Thamama</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

- 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:
The cement can never be pumped higher in the annulus than the lost circulation zone. In this case there will always be a fluid above the lost circulation zone.

The cement reached to surface but dropped again to a level which cannot be exactly anticipated. In this case there will be no fluid from the top of cement to surface.

- Monitor annulus carefully during primary cementing. 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:

- 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 does not exceed 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

<table>
<thead>
<tr>
<th>Potential Hazards</th>
<th>How to mitigate</th>
</tr>
</thead>
</table>
| 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 Ruwaydah 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 |

S.G.  
Rev-0/05

HDO(S/N/E) : Date :
HDO(BU/BB) : Date :
DM : Date :
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Printed on: 02/03/2005
<table>
<thead>
<tr>
<th>Potential Hazards</th>
<th>How to mitigate</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Install string stabilizers within the drill string to ensure ‘stand-off’ from the wellbore. This could compromise directional (build) capability.</td>
<td></td>
</tr>
<tr>
<td>• 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</td>
<td></td>
</tr>
<tr>
<td>• Control water loss, minimize mud cake building tendency.</td>
<td></td>
</tr>
<tr>
<td>• Monitor filter cake quality.</td>
<td></td>
</tr>
<tr>
<td>• 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.</td>
<td></td>
</tr>
<tr>
<td>• Solids removal equipment should be used with full performance and efficiency</td>
<td></td>
</tr>
<tr>
<td>Tight hole</td>
<td>While drilling with aerated mud, maintain high fluid pumping rates above 850 GPM.</td>
</tr>
<tr>
<td>• 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:</td>
<td></td>
</tr>
<tr>
<td>• i) hydrostatic head increases</td>
<td></td>
</tr>
<tr>
<td>• ii) losses occur in the lower formation</td>
<td></td>
</tr>
<tr>
<td>• iii) differential sticking is possible</td>
<td></td>
</tr>
<tr>
<td>• iv) hole pack off could also occur during connection.</td>
<td></td>
</tr>
<tr>
<td>• Use aerated fluid of maximum 56 pcf equivalent density.</td>
<td></td>
</tr>
<tr>
<td>• Minimize time spent at connections without pipe motion.</td>
<td></td>
</tr>
<tr>
<td>• Consider wiper trip at top Simsima if hole condition dictates.</td>
<td></td>
</tr>
<tr>
<td>• Stabilize BHA using roller reamers.</td>
<td></td>
</tr>
<tr>
<td>• To minimize chances of stuck pipe, avoid pulling above 30 klb.</td>
<td></td>
</tr>
<tr>
<td>• Do not fight your way in or out of the hole.</td>
<td></td>
</tr>
<tr>
<td>• In case of sudden complete loss, try to continue drilling with controlled GPM and ROP, circulating at least one bottom up prior to POH.</td>
<td></td>
</tr>
<tr>
<td>Drill string corrosion</td>
<td>• High O₂ content in aerated mud accelerates corrosion, especially where the drill string coating is broken.</td>
</tr>
<tr>
<td>• Inspect drill string regularly.</td>
<td></td>
</tr>
<tr>
<td>• Use 8% sodium silicate, inhibited with bentonite to reduce corrosion rate.</td>
<td></td>
</tr>
<tr>
<td>Ledging and hole spiraling</td>
<td>• 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.</td>
</tr>
<tr>
<td>• 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.</td>
<td></td>
</tr>
</tbody>
</table>
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 45° and 65° present the most problems with drilled cuttings having a tendency to slide down the annulus and ‘pack-off’. Hole angles greater than 65° 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>
<thead>
<tr>
<th>S. N.</th>
<th>Description</th>
<th>Grade</th>
<th>Wt lb/ft</th>
<th>Thread</th>
<th>MESC No.</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Casing, R3</td>
<td>L-80</td>
<td>47</td>
<td>N.VAM</td>
<td>04-12-15-370-9</td>
</tr>
<tr>
<td>2</td>
<td>Casing, R3</td>
<td>L-80</td>
<td>47</td>
<td>NK3SB</td>
<td>04-12-15-370-9</td>
</tr>
<tr>
<td>3</td>
<td>Casing Pup (5’)</td>
<td>L-80</td>
<td>47</td>
<td>N.VAM</td>
<td>04-12-15-205-9</td>
</tr>
<tr>
<td>4</td>
<td>Casing Pup (10’)</td>
<td>L-80</td>
<td>47</td>
<td>N.VAM</td>
<td>04-12-15-210-9</td>
</tr>
<tr>
<td>5</td>
<td>Casing Pup (20’)</td>
<td>L-80</td>
<td>47</td>
<td>N.VAM</td>
<td>04-12-15-220-9</td>
</tr>
<tr>
<td>6</td>
<td>Casing Pup (5’)</td>
<td>L-80</td>
<td>47</td>
<td>NK3SB</td>
<td>04-12-15-205-9</td>
</tr>
<tr>
<td>7</td>
<td>Casing Pup (10’)</td>
<td>L-80</td>
<td>47</td>
<td>NK3SB</td>
<td>04-12-15-210-9</td>
</tr>
<tr>
<td>8</td>
<td>Casing Pup (20’)</td>
<td>L-80</td>
<td>47</td>
<td>NK3SB</td>
<td>04-12-15-220-9</td>
</tr>
<tr>
<td>9</td>
<td>Float collar (N.R)</td>
<td>L-80</td>
<td>43.5–47</td>
<td>VAM</td>
<td>05-14-26-610-9</td>
</tr>
<tr>
<td>10</td>
<td>Float shoe</td>
<td>L-80</td>
<td>43.5–47</td>
<td>VAM</td>
<td>05-14-26-668-9</td>
</tr>
<tr>
<td>11</td>
<td>Float collar (N.R)</td>
<td>L-80</td>
<td>43.5–47</td>
<td>NK3SB</td>
<td>05-14-26-612-9</td>
</tr>
<tr>
<td>12</td>
<td>Float shoe</td>
<td>L-80</td>
<td>43.5–47</td>
<td>NK3SB</td>
<td>05-14-26-750-9</td>
</tr>
<tr>
<td>13</td>
<td>O.H. Centralizer</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>05-17-25-126-9</td>
</tr>
<tr>
<td>14</td>
<td>positive Centralizer</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>05-17-30-135-1</td>
</tr>
</tbody>
</table>
Dimensions, mechanical properties and make up torque of the 9 ⅝” casing is tabulated in the following table:-

<table>
<thead>
<tr>
<th>Description</th>
<th>Grade</th>
<th>Wt lb/ft</th>
<th>Thread</th>
<th>MESC No.</th>
</tr>
</thead>
<tbody>
<tr>
<td>15 Stop Collar</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>05-17-55-110-1</td>
</tr>
<tr>
<td>16 Casing Dope</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>87.47.25.07.09</td>
</tr>
<tr>
<td>17 Thread Compound</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>87.42.47.24.09</td>
</tr>
</tbody>
</table>

Table 2-32: 9 ⅝” Casing Properties

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

11.1.2 Wellhead

<table>
<thead>
<tr>
<th>S. N.</th>
<th>Description</th>
<th>Quantity</th>
<th>MESC No.</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Fluted casing hanger 13 ⅝” x 9 ⅝”</td>
<td>1</td>
<td>09.20.22.865.9</td>
</tr>
<tr>
<td>2</td>
<td>Tubing Head Spool 13 ⅝”x11”– 5 M</td>
<td>1</td>
<td>09.21.40.635.9</td>
</tr>
</tbody>
</table>

12. Waste Management

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

Printed on: 02/03/2005
- 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.
SECTION 6

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
### Surface (G.L)

<table>
<thead>
<tr>
<th>Layer</th>
<th>SAHIL</th>
<th>DHABBIYA</th>
</tr>
</thead>
<tbody>
<tr>
<td>Surface Sand</td>
<td>30° C.P. 3 Jts</td>
<td>30° C.P. 1 Jt</td>
</tr>
<tr>
<td>Miocene</td>
<td>18 ½” Csg</td>
<td>18 ½” Csg</td>
</tr>
<tr>
<td>Dammam</td>
<td>13 3/8” Csg</td>
<td>13 3/8” Csg</td>
</tr>
<tr>
<td>RUS</td>
<td>13 3/8” Csg</td>
<td>13 3/8” Csg</td>
</tr>
<tr>
<td>Simsima</td>
<td>13 3/8” Csg</td>
<td>13 3/8” Csg</td>
</tr>
<tr>
<td>Fiqqa</td>
<td>13 3/8” Csg</td>
<td>13 3/8” Csg</td>
</tr>
<tr>
<td>Shelaif</td>
<td>9 ½” Csg</td>
<td>9 ½” Csg</td>
</tr>
<tr>
<td>Nahr Umr</td>
<td>9 ½” Csg</td>
<td>9 ½” Csg</td>
</tr>
<tr>
<td>Bab Member</td>
<td>9 ½” Csg</td>
<td>9 ½” Csg</td>
</tr>
<tr>
<td>Thamama</td>
<td>TD</td>
<td>TD</td>
</tr>
<tr>
<td>Zone A</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Zone B</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Zone C</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Habshan 2</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
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 ¾” 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 ± 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)

<table>
<thead>
<tr>
<th>Size</th>
<th>Description</th>
<th>No.</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>8 ½”</td>
<td>Tricone Bit</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>6.3/4”</td>
<td>Motor</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>6.3/4”</td>
<td>N.M. Drill Collar</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>6.3/4”</td>
<td>Hang off Sub</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>6.1/2”</td>
<td>Orient Sub</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>6.5/8”</td>
<td>N.M. Drill collar</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>6.3/4”</td>
<td>MWD/LWD</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>5”</td>
<td>Drill pipe</td>
<td></td>
<td>Number depends on the length of departure</td>
</tr>
<tr>
<td>5”</td>
<td>HWDP</td>
<td>30</td>
<td></td>
</tr>
<tr>
<td>6.1/2”</td>
<td>Drilling Jar</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>5”</td>
<td>HWDP</td>
<td>12</td>
<td></td>
</tr>
<tr>
<td>5”</td>
<td>Crossover</td>
<td>1</td>
<td></td>
</tr>
</tbody>
</table>
4.2.2 Option 2 (Directional Drilling)

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

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

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

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

<table>
<thead>
<tr>
<th>Size</th>
<th>Description</th>
<th>No.</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>8 ½”</td>
<td>PDC Bit</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>6 ¾”</td>
<td>Motor</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>8 ¼”</td>
<td>S. Stab</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>6 ½”</td>
<td>Drill collar</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>8 ¼”</td>
<td>S. Stab</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>6 ½”</td>
<td>Drill collar</td>
<td>12</td>
<td></td>
</tr>
<tr>
<td>6 ½”</td>
<td>Drilling Jar</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>6 ½”</td>
<td>Drill collar</td>
<td>3</td>
<td></td>
</tr>
<tr>
<td>5”</td>
<td>HWDP</td>
<td>12</td>
<td></td>
</tr>
<tr>
<td>5”</td>
<td>Crossover</td>
<td>1</td>
<td></td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th>Formation</th>
<th>Directional Issues</th>
</tr>
</thead>
<tbody>
<tr>
<td>Shilaif</td>
<td>• Hard formation. Difficult to kick off. Sliding slowly to build up angle.</td>
</tr>
<tr>
<td></td>
<td>• Common bit damage due to high compressive strength of the formation.</td>
</tr>
</tbody>
</table>
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 verify 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.
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

<table>
<thead>
<tr>
<th>Application</th>
<th>Bow Type</th>
<th>Rigid Type</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Non-Weld</td>
<td>STT-I-SL</td>
</tr>
<tr>
<td>Rotating liner applications</td>
<td>Not to be used</td>
<td>Excellent</td>
</tr>
<tr>
<td>Drag force minimization required</td>
<td>Not optimized</td>
<td>Excellent</td>
</tr>
<tr>
<td>High build-up rate</td>
<td>Good</td>
<td>Good</td>
</tr>
<tr>
<td>Passing restrictions in the wellbore</td>
<td>Good</td>
<td>Good</td>
</tr>
</tbody>
</table>

S.G. Rev-0/05

HDO(S/N/E) : Date :

HDO(BU/BB) : Date :

DM : Date :

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Printed on: 02/03/2005
### 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 ⅜” 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 torque.

• 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 unweighted 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
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 below. 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.
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)

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

8. Drilling Hazards

Table 2-40: Hole Drilling Hazards in 8 1/2"

<table>
<thead>
<tr>
<th>Potential Hazard</th>
<th>How to Mitigate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stuck Pipe</td>
<td>• 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.</td>
</tr>
<tr>
<td></td>
<td>• Installing string stabilizers within the drillstring to ensure ‘stand-off’ from the wellbore in permeable reservoir formations will compromise directional (build) capability.</td>
</tr>
<tr>
<td></td>
<td>• 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.</td>
</tr>
<tr>
<td></td>
<td>• 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.</td>
</tr>
<tr>
<td></td>
<td>• 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.</td>
</tr>
<tr>
<td>Well Control</td>
<td>• 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”.</td>
</tr>
</tbody>
</table>
9. Equipment Required

9.1 Casing Accessories Equipment

Table 2-41: 7” Liner Casing and Accessories

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

9.2 Dimensions and Mechanical Properties for 7” Casing

Table 2-42: 7” Casing Properties

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

<table>
<thead>
<tr>
<th>Hole Size</th>
<th>Mud Salinity</th>
<th>Rental Equipment</th>
<th>Mud Handling</th>
<th>Cuttings Handling</th>
</tr>
</thead>
<tbody>
<tr>
<td>8 ½”</td>
<td>Oil Base Mud</td>
<td>Air Pumps 1</td>
<td><strong>NO DUMPING</strong> Mud to be stored for either recycling or to be transferred to injection disposal well</td>
<td>Cuttings to be drayed using H&quot;G&quot; dryer and transferred to cutting treatment plant into sealed cutting boxes.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Auger 1</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Tanks 4</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Centrifuge 1</td>
<td></td>
<td></td>
</tr>
<tr>
<td>8 ½”</td>
<td>Water Base Mud</td>
<td>Tanks 4</td>
<td><strong>NO DUMPING</strong> Excess mud to be transported to injection disposal well.</td>
<td>Cuttings to be piled on location and to be used to bund the location.</td>
</tr>
</tbody>
</table>

- 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.
SECTION 7

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

<table>
<thead>
<tr>
<th>Surface (G.L.)</th>
<th>BAB</th>
<th>ASAB</th>
</tr>
</thead>
<tbody>
<tr>
<td>Surface Sand</td>
<td>30” C.P. 3 Jts</td>
<td>30” C.P. 3 Jts</td>
</tr>
<tr>
<td>Miocene</td>
<td>18 3/8” Csg</td>
<td>30” C.P. 1 Jt</td>
</tr>
<tr>
<td>Dammam</td>
<td>13 3/8” Csg</td>
<td>18 3/8” Csg</td>
</tr>
<tr>
<td>RUS</td>
<td>18 3/8” Csg</td>
<td>13 3/8” Csg</td>
</tr>
<tr>
<td>Simsima</td>
<td>9 3/8” Csg</td>
<td>13 3/8” Csg</td>
</tr>
<tr>
<td>Fiqa</td>
<td>9 3/8” Csg</td>
<td>13 3/8” Csg</td>
</tr>
<tr>
<td>Shilaif</td>
<td>9 3/8” Csg</td>
<td>13 3/8” Csg</td>
</tr>
<tr>
<td>Nahr Umr</td>
<td>9 3/8” Csg</td>
<td>13 3/8” Csg</td>
</tr>
<tr>
<td>Bab Member</td>
<td>9 3/8” Csg</td>
<td>13 3/8” Csg</td>
</tr>
<tr>
<td>Zone B</td>
<td>7” Liner TD</td>
<td>7” Liner TD</td>
</tr>
<tr>
<td>Zone C</td>
<td>7” Liner TD</td>
<td>7” Liner TD</td>
</tr>
<tr>
<td>Subunit 7</td>
<td>Zone C or B</td>
<td>Zone C or B</td>
</tr>
<tr>
<td>Zone D</td>
<td>7” Liner TD</td>
<td>7” Liner TD</td>
</tr>
</tbody>
</table>

S.G. Rev-0/05 HDO(S/N/E) : Date : HDO(BU/BB) : Date : DM : Date : Page 2-112

Printed on: 02/03/2005
<table>
<thead>
<tr>
<th>Surface (G.L)</th>
<th>BU-HASA</th>
<th>SHAH</th>
</tr>
</thead>
<tbody>
<tr>
<td>Surface Sand</td>
<td>40° C.P. 1 jt</td>
<td>30° C.P. 3 Jts</td>
</tr>
<tr>
<td>Miocene</td>
<td>30° C.P. 18&quot; Csg</td>
<td>18 3/8&quot; Csg</td>
</tr>
<tr>
<td>Dammam</td>
<td>13 3/8&quot; Csg</td>
<td>18 3/8&quot; Csg</td>
</tr>
<tr>
<td>RUS</td>
<td>9 5/8&quot; Csg</td>
<td>9 5/8&quot; Csg</td>
</tr>
<tr>
<td>Simsima</td>
<td>7&quot; Liner TD</td>
<td>7&quot; Liner TD</td>
</tr>
<tr>
<td>Fiqqa</td>
<td>7&quot; Liner TD</td>
<td>7&quot; Liner TD</td>
</tr>
<tr>
<td>Shilaif</td>
<td>9 5/8&quot; Csg</td>
<td></td>
</tr>
<tr>
<td>Nahr Umr</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Shuaiba</td>
<td>7&quot; Liner TD</td>
<td></td>
</tr>
<tr>
<td>Shuaiba</td>
<td></td>
<td></td>
</tr>
<tr>
<td>S. Unit D or G</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Legend:**
- Csg: Cemented Screened Grout
- C.P.: Casing Point
- TD: Total Depth
• 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 5/8” scraper in tandem to cleanout 7” liner and 9 5/8” casing.
• If Cement Quality Parameters (CQP) are NOT FULLY SATISFIED (see CQP
 table in 8 1/2” 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)

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

3.2.2 Option 2 (Horizontal Drilling)

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

<table>
<thead>
<tr>
<th>Size</th>
<th>Description</th>
<th>No.</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>6”</td>
<td>PDC</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>6”</td>
<td>RSS</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>4.3/4”</td>
<td>NMDC</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>4.3/4”</td>
<td>LWD Tool</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>4.3/4”</td>
<td>MWD Pulser</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>5.7/8”</td>
<td>S. Stabilizer</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>4.3/4”</td>
<td>Drill collar</td>
<td>1</td>
<td></td>
</tr>
</tbody>
</table>
3.3 Special Tools

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

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

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

Note:
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.

3.4 Directional Challenges

The following table highlights the potential directional challenges associated with each formation during drilling the 6” hole.
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>
<thead>
<tr>
<th>Hole Size</th>
<th>Formation Interval</th>
<th>Logs typically required</th>
</tr>
</thead>
<tbody>
<tr>
<td>6”</td>
<td>Reservoir</td>
<td>LWD (Resistivity, Density, Neutron, GR), FMI, MDT</td>
</tr>
</tbody>
</table>

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 35°, 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

<table>
<thead>
<tr>
<th>Potential Hazard</th>
<th>Hoe to mitigate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stuck Pipe</td>
<td>• Minimize sliding intervals and periods and if possible keep pipe in rotation all the time.</td>
</tr>
<tr>
<td></td>
<td>• 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.</td>
</tr>
<tr>
<td></td>
<td>• 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.</td>
</tr>
<tr>
<td></td>
<td>• Watch torque, pressure and drag carefully while drilling horizontal hole</td>
</tr>
<tr>
<td></td>
<td>• When the hole is packed off, jarring up is not the correct initial response and should be avoided.</td>
</tr>
<tr>
<td></td>
<td>• If while POOH tight hole are encountered, do not exceed 30,000 lbs over pull, attempt to go back and circulate hole clean.</td>
</tr>
<tr>
<td></td>
<td>• Control tripping speed (2min/stand) to avoid swabbing and formation mechanical damage.</td>
</tr>
<tr>
<td>Differential</td>
<td>• Ensure preventative drilling practices are strictly adhered to i.e. moving and rotating drill-string as much as possible, minimizing length of unstabilised BHA.</td>
</tr>
<tr>
<td>sticking</td>
<td>• Use spiral Drill Collars and HWDP.</td>
</tr>
</tbody>
</table>
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. | • 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

<table>
<thead>
<tr>
<th>Hole Size</th>
<th>Mud Salinity</th>
<th>Rental Equipment</th>
<th>Mud Handling</th>
<th>Cuttings Handling</th>
</tr>
</thead>
</table>
| 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.
Chapter 3

WELL CONTROL

Revision-0
March 2005
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SECTION 1

WELL CONTROL PRINCIPLES

ADCO’s well control policy is to have pressure barriers that prevent uncontrolled flows of oil, gas or water either to the surface or sub surface during drilling, workover and production operations. All field operations shall be conducted in such a way that operations do not expose to unreasonable well control risks.

1. Primary Control

Primary well control is maintained by controlling formation pore pressures with the hydrostatic pressure of the drilling fluid.

\[
\text{Hydrostatic pressure (psi) = MW (pcf) \times Depth (ft)/144}
\]

Where operations are to be carried out without primary well control (i.e. with the well under pressure). A BOP System that meet the minimum requirements shall be used with addition of a means of containing well pressure while pipe, cable or tubing is moving through the wellhead.

2. Secondary Control

A secondary means of providing pressure control in the event of loss of primary control shall be provided by installing a Blowout Preventer or Diverter System.

In an emergency and extreme case, and where secondary control is not reliable due to equipment failure or hole conditions, tertiary procedures can be employed.

3. Tertiary Control

Tertiary procedures are the 'last resort' and to be considered only in an emergency situation. In most cases it is expected to lose the well or part of the hole. Two common types of tertiary control techniques are:

3.1 Barite plugs

A barite plug is a slurry mixture of barite in fresh water or diesel oil that is placed in the hole via the workstring. The idea is that the solids settle out rapidly to form an impermeable plug when left quiescent. This plug is impermeable and is known to be capable of isolating producing zones and holding very high pressures.
3.2 Cement plugs

Cement plugs may be used to isolate downhole flows. Cementing is also considered a ‘last’ option and should only be used if there is no other choice. Note that cementing will most likely result in the loss of the well and total abandonment. It may also cause the tools and workstring to be cemented in place.
SECTION 2

CAUSES OF KICK

The KICK can be defined as, any influx of formation fluids into the borehole that causes an equal volume of drilling fluid to be displaced out of the hole\(^1\).

1. Causes of induced kicks

Almost 70% of kicks are induced kicks and they occur due to human error. The induced kicks occur in the following cases.

- Failure to keep hole full of mud while tripping
- Swabbing (hole not taking proper amount of fluid, high mud viscosity, POOH too fast, bit balling . . . )
- Surging (high viscosity, RIH too fast, Bit balling )
- Trip gas (gas cut mud)
- Mud weight is not correct.

2. Causes of unbalanced kicks

- Abnormally low pressure (formation fractured, loss of circulation)
- Abnormally high pressure zones usually located below shale formation

\(^{1}\) Solubility of gas in OBM should be considered.
SECTION 3

PREVENTION OF KICK

Proper planning, correct tripping procedures, and maintaining suitable hydrostatic pressure are the main three factors for preventing a kick.

1. Planning

In order to minimize the well control incidents, the following preparations are required and should be followed without any deviation unless dispensation is approved by Drilling Division Management.

1.1 Equipment Hookup

- The policy of ADCO is to line up the BOP, Choke Manifold, and surface lines for HARD SHUT-IN.

  **Note:** Hard Shut-in means that the choke line valves (HCR & remote chock) on choke line and choke manifold are in closed position while drilling and remain closed until after the preventer is sealed and well shut-in.

- The trip tank is used to monitor pipe displacement.
- PVT for active tanks during drilling/coring mode.

1.2 Well Control Drills

The purpose of well control drills is to familiarize the drill crews with techniques that will be implemented in the event of a kick and to ensure that the equipment integrity is in place in case of emergency. One of the major factors that influence the wellbore pressures after a kick is taken is the volume of the influx. The smaller the influx, the less severe will be the pressures during the well kill operation. The following table listing the drills required by ADCO.

<table>
<thead>
<tr>
<th>Code</th>
<th>Drill or Test</th>
<th>Frequency</th>
</tr>
</thead>
<tbody>
<tr>
<td>D1</td>
<td>Kick Drill While Drilling</td>
<td>Once Per Week Per Shift</td>
</tr>
<tr>
<td>D2</td>
<td>Kick Drill While Tripping</td>
<td>Once Per Week Per Shift</td>
</tr>
<tr>
<td>D3</td>
<td>Accumulator Automatic Switch On/Off Control</td>
<td>Twice Per Week</td>
</tr>
<tr>
<td>D4</td>
<td>Well Kill Drill</td>
<td>Twice Per Well Per Shift</td>
</tr>
<tr>
<td>D5</td>
<td>Diverter Drill</td>
<td>Once Per Well Per Shift</td>
</tr>
<tr>
<td>O1</td>
<td>PVT</td>
<td>Daily and For D1, D2 &amp; D4</td>
</tr>
<tr>
<td>O2</td>
<td>Degasser</td>
<td>Check Once Per Week</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>S.G. Rev-0/05</th>
<th>HDO(S/N/E) : Date :</th>
<th>HDO(BU/BB) : Date :</th>
<th>DM : Date :</th>
<th>Page 3-6</th>
</tr>
</thead>
</table>

Printed on: 02/03/2005
For detailed well control drills, refer to Section 8.

1.3 Slow Pump Rate (SPR)

There are many reasons why a kick should be displaced from the hole at a rate that is considerably slower than that used during normal drilling, these include:

- To minimize the pressure exerted on the open hole
- To allow weighting of the mud as the kick is displaced
- To ensure safe removal of gas from the returned mud utilizing the poor boy degasser and mud gas separator
- To limit the speed of required choke adjustments
- To reduce the pressure exerted on well control equipment

SPR should be conducted as follow:

- It should be conducted for each pump separately
- It should be conducted at two different pump rate (30 stroke/min and 45 stroke/min)
- Pressures should be recorded from the same killing operation gauges.
- Report the slow pump rates and pressures in the morning report.

SPR should be conducted regularly and at least:

- When the bit or BHA is changed
- When the mud weight or properties are changed
- When the mud pump liner size is changed
- Every 500 ft drilled.

2. Correct Tripping Procedure

Industry-wide experience has shown that the majority of well control problems have occurred during trips. It is therefore particularly important that special attention is paid to ensure correct tripping procedure.

Pore pressure can only be definitively assessed on the basis of observations of trip gas, connection gas, swab gas and pump off gas. If any of these are observed then pore pressure levels are closed to mud hydrostatic.
Increasing background gas levels can indicate increasing pore pressure of correctly determined and analyzed, it is important that the drilled gas level content of background gas is understood.

For definition purposes the level of gas in the mud is due to one or a combination of the following:-

- **Background Gas**
  The general level of gas carried by the mud purely as a function of circulating in open hole.

- **Drilled Gas**
  Gas which has entered the mud due to the actual drilling of the formation. i.e. the gas contained in the matrix of the rocks which have been drilled.

- **Swabbed Gas**
  The gas which enters the well due to swabbing. This may be caused by tripping or by simulating tripping.

- **Trip Gas**
  The gas which enters the mud during a trip which is measured after a trip has taken place.

- **Pump Off Gas (Connection Gas)**
  The gas which enters the mud due to turning off the mud pumps and removing ECD from the hydrostatic pressure on the bottom of the well; especially during connections or swabbing while pulling back.

### 2.1 Prior to Tripping

Considerable preparation is required before the trip is commenced. The following are among the most important actions that should be carried out prior to tripping:

#### 2.1.1 Circulate the Hole

- The mud should be conditioned to ensure that tripping will not cause excessive swab/surge pressures
- Any entrained gas or cuttings should be circulated out
- The mud weight should be such as to ensure an adequate overbalance will exist at all times during the trip
2.1.2 Determine the Maximum Pipe Speed

- Swab/surge pressures should be calculated at various tripping speeds using the appropriate formula.
- The maximum average pipe speed should be selected bearing in mind the estimated overbalance or trip margin

2.1.3 Line Up the Trip Tank

- A trip tank shall be available and be complete with a volume indicator easily read from the driller's position.
- It is considered unsafe to trip without a trip tank and as such, spare parts for the hole fill pump/motor should be kept at the rig site

2.1.4 Fill In the Trip Sheet

- In order that maximum use is made of the trip tank on trips in and out of the hole, a trip sheet should be used to record the mud volumes required to keep the hole full.
- Trip sheets shall be filled out by the driller on every trip in and out of the hole. Any deviation from expected hole fill-up volumes shall be reported to DS and RM and investigated.
- The trip sheet for the last trip out of the hole should be signed by driller, reviewed and signed by both RM and DS.

2.1.5 Drill Floor Preparation

- Crossovers should be available on the rig floor to allow a full opening drillpipe safety valve to be made up to each tubular connection that is in the hole
- A tested drillpipe safety valve (Kelly valve) should be available on the rig floor. (It should be kept in the open position)
- A backup safety valve, such as a Gray valve, should be available on the rig floor. This valve should only be used in the event that the drillpipe safety valve does not hold pressure, or if stripping in the hole is required and no dart sub is fitted
- The rig crew should be completely familiar with, and practiced in, their responsibilities in the event of a kick.
2.2 Tripping Procedure

Having completed the preparations as outlined previously, the trip out of the hole can be started. The following procedure is proposed as a guideline:

- Flowcheck the well with the pumps off to ensure that the well is stable with the ECD (equivalent circulating density) effect removed.

- Pump a slug which enables the pipe to be pulled dry and the hole to be accurately monitored during a trip. As a general rule, the slug should be mixed to maintain a minimum of 2 stands of dry pipe. It is important to accurately displace the slug to the pipe. In this manner, the Driller will know the weight, depth and height of the slug at all times during the trip.

- For the first 5 to 10 stands off bottom, monitor the hole through the rotary. This is to check that the annulus is falling as pipe is removed from the hole. The pipe wiper should therefore be installed only after the first stands have been pulled. The trip tank should not be overfilled at this stage to ensure that swabbing is clearly indicated, should it occur. The circulating pump should be switched off at this stage and the hole filled from the trip tank, after each stand.

- Circulate the hole across the trip tank and continue to trip out, monitoring hole volumes with the aid of the trip sheet.

- Conduct a flow check when the BHA is inside the casing shoe.

- Conduct a flow check prior to pulling the BHA through the stack.

- Be aware that the required hole fills volume per stand of heavy weight and drill collars will be greater than for drillpipe as the BHA is being removed from the hole.

- Once back on bottom, the overbalance can be assessed from the level of the trip gas at bottoms up. If the hole does not take the correct amount of fluid at any stage in the trip, a flow check should be carried out.

- If the flow check is positive, the well should be shut in according to the procedure indicated in the standing orders (for shut in procedure refer to Section 5 of this chapter). Subsequent action will be dependent upon the conditions at the rig site.

2.3 Special Procedure for Oil Based Mud

When oil-based mud is in use, gaseous fluids have a tendency to go into solution with the mud at high temperature and pressure. Experience has shown that once an influx has gone into solution, it will not break out of solution until the bubble point is reached, typically at 1000 to 1500 psi (this will depend on the fluids concerned). The possible consequence of this is that
a small influx that was undetected at depth may suddenly break out of solution close to the surface. This may cause a dangerous liberation of gas at surface as well as significant reduction in hydrostatic pressure in the well.

Consideration should also be given to the possibility of thermal expansion of the mud at high temperatures and compressibility at low temperatures. This can cause a reduction in effective mud weight and hence in the overall hydrostatic head.

It is therefore recommended that tripping procedures are modified to take account of this potential problem when oil-based mud is in use in the following situations:

- When drilling or coring in a potential pay zone.
- On prediction of an increase in pore pressure.
- On detecting significant levels of gas in the mud.

In these circumstances, the following procedures are recommended prior to pulling out of the hole:

- Flow check the well.
- Circulate bottoms up.
- Check trip to 10 stands or to the shoe monitoring hole volumes.
- Flow check at the shoe and run back to bottom.
- Circulate bottoms up. Close in the Blowout Preventer (BOP) and circulate through the choke when the potential influx is at 1500ft below the stack, watching for any pit gain.
- If necessary, increase the mud weight and perform a further check trip.

This procedure can be relaxed if, after several trips under the same conditions, the well remains stable.

The following procedures are recommended in these circumstances after a round trip:

- When back on bottom prior to any further drilling or coring, circulate bottoms up to check for trip gas.
- Circulate until potential influx is at 1500ft below the stack, watching for any pit gain.
- Close in the well and circulate the potential influx through the choke.
3. Maintain Suitable Hydrostatic Pressure

3.1 General

Primary well control is achieved by controlling formation pressures with the hydrostatic pressure of the drilling fluid.

Hydrostatic pressure will be reduced once drilling stops as a result of the loss of annulus frictional pressure and the removal of cuttings from the annulus. The settling of cuttings to the bottom of the hole may significantly reduce the hydrostatic pressure further up the hole.

Industry-wide experience has shown that the most common causes of loss of primary control and hence the well kicks are:

- Swabbing during trips
- Not adequately filling the hole during a trip
- Insufficient mud weight
- Lost circulation

The evidence also shows that the majority of kicks have occurred during trips.

3.2 Cuttings Contamination

One of the most important functions of the drilling fluid is to transport cuttings from the bit to the surface. The presence of cuttings in the annulus will increase the effective hydrostatic pressure of the fluid column. If this increase is excessive, it can cause losses which may possibly lead to the loss of primary control.

It is therefore useful to be able to estimate the additional pressure caused by the cuttings in the annulus. In order to be able to estimate this additional pressure, a measure of the ability of the drilling fluid to remove the cuttings from the well is required.
SECTION 4

WARNING SIGNS OF KICK

Early kick detection and quick reaction is the single most important aspect of well control and shall be the absolute prime objective at ALL times.

The following are the signs that indicate either a kick has occurred or that a kick may soon develop.

1. Kick Signs

1.1 Drilling Break

One of the first indications that a kick may occur is increase in penetration rate, or a drilling break.

A change in one or more of the formation parameters (lithology, porosity, permeability) may increase drilling rate (Drilling Break) and create the conditions in which a kick could occur.

For the above reason any drilling break should be checked for flow.

1.2 Increase Return Flowrate

Increase return flowrate is the first confirmation that a kick has occurred.

The detection of the increase in flow rate will be affected by the specific gravity of the influx and the length of the influx source formation.

1.3 Pit Gain

In order to detect the very small influx volumes, all efforts should be made to ensure that pit levels are accurately monitored at all times.

Generally a gain in pit volume that was not due to movement of mud stocks in the mud system is confirmation that a kick is occurred.

Mud system monitors should be able to detect pit gain of 5 bbls or less.

1.4 Hole Not Taking Appropriate Volume during a Trip

During tripping out of the hole, it is essential that the appropriate volume of mud is used to keep the hole full. If the hole takes less mud than expected, this should be taken as positive indication that an influx has been swabbed into the hole.
At any stage while tripping out of the hole, and if the hole does not take the correct volume of mud, the pipe should be run back to bottom using the trip tank, and bottoms-up circulated.

Depending on the situation, Stripping should be considered to prevent kick from expansion and migrate to the surface.

### 1.5 Gas Cut Mud

A minor influx that is not detected as a pit gain may first be identified at surface in the returned mud. Formation fluids and gas in the returned mud may therefore indicate that a low volume influx is occurring or has occurred.

Gas can enter the mud for one or more of the following reasons:

- As a result of drilling a formation that contains gas even with a suitable overbalance
- As a result of a temporary reduction in hydrostatic pressure caused by swabbing as pipe is moved out of the hole
- Due to the pore pressure in a formation being greater than the hydrostatic pressure of the mud column.

The Driller should first assume that a kick may have occurred and flowcheck the well.

There are some other minor signs which could help to detect kick.

- Sudden torque increase.
- Change in mud chlorides.
- Change of pump speed or pump pressure.
- Increase the Hook load.
- Change in flowline temperature.
- Drilling break.
- Change in shale density.
- Tight connections and fill on connections.
- Stuck pipe and resultant pump pressure indications (potential for bridge or pack-off with flow from above).
SECTION 5

WELL KILLING PROCEDURE

1. Introduction

This section covers the basic steps that are required to implement the killing methods.

All the following well control techniques are designed to ensure that: bottomhole pressure is maintained constant and equal to, or slightly greater than, the formation pressure.

The choice of kick circulation method will be based upon the specific well conditions.

Advantages and limitations of those methods should be evaluated and calculations should be done to aid in this choice. Advantages and limitations for the killing methods will be shown later in this section.

2. Shut-in procedure

When a kick is detected, it is important to follow the proper sequence of shut in the well. As per ADCO policy HARD SHUT-IN is the method to be used in case of positive flow check.

There are two cases of shut-in procedure depend on the position of the bit.

2.1 Shut-in the well while drilling (Bit on bottom)

The following procedures are to be followed to shut-in the well while drilling:

- Stop rotary.
- Raise Kelly / Top Drive until no tool joint is across any pipe ram.
- Shut down the mud pumps.
- Flow check the well.
- If positive: Close Annular preventer (or top pipe ram).
- Confirm the well shut-in.
- Open choke line (HCR) at BOP stack.
- Record shut-in pressure and pit gain.
2.2 Shut-in the well while tripping (Bit off bottom)

The following procedures are to be followed in case of positive flow check while tripping.

- Set drill string in slips
- Install and make up the fully opened Safety Valve in the drill string.
- Close the Safety Valve
- Close Annular preventer
- Confirm the well shut-in
- Open choke line (HCR) at BOP stack
- Pick up and make up Kelly (Top Drive)
- Open Safety Valve
- Record Shut-in pressure and pit gain

2.3 Shut—in Procedure with BHA across BOP Stack

- Set BHA on slips
- Install and make up the fully opened Safety Valve.
- Close the Safety Valve
- Close Annular preventer
- Confirm the well shut-in
- Open choke line (HCR) at BOP stack
- Install Gray Valve.
- Open Safety Valve
- Make up one stand of drillpipe
- Record SICP.
- Reduce closing pressure in annular preventer.
- Strip in one stand of drillpipe through annular
- Pick up and make up Kelly (Top Drive)
- Record Shut-in pressure and pit gain
In the event of a failure in the annular (with BHA across BOP Stack) and uncontrolled flow, the emergency response should consist of dropping the BHA and shutting in the well with blind ram.

**Note:**

Low torque valves shall not be used to secure a string under any circumstances. Only right hand Kelly cocks shall be used as string shut off tools.

### 3. Pre-killing Preparations

There are some preparations that has to be done before starting the killing operation, these preparations are required in all killing methods.

#### 3.1 Allow the Well to Stabilize

After the well is shut in, it may take a few minutes for the shut in pressures to stabilize. In case the drillpipe float is not installed, record the shut-in casing pressure (SICP) and the shut-in drillpipe pressure (SIDP).

#### 3.2 Bumping the Drillpipe Float

In case where there is a drill pipe float, the following procedures are required to obtain the SIDP pressure.

a) Make sure the well is shut-in and that the shut-in casing pressure is recorded.

b) Slowly pump down the drill pipe while monitoring both the casing and drill pipe pressure.

c) The drill pipe pressure will increase as pumping is begun. Watch carefully for a “lull” (a hesitation in the rate of increase) in the drill pipe pressure which will occur as the float is pumped off its seat. Record the drill pipe pressure when the lull is first seen.

d) To verify that the float has been pumped open, continue pumping down the drill pipe very slowly until an increase in the casing pressure is observed. This should occur very soon after the lull was recorded on the drill pipe gauge.

e) Shut down the pumps as soon as you see the casing pressure start to increase and record the shut-in drill pipe pressure as the pressure at which the lull was first seen in step(c).

#### 3.3 Perform the Kick Control Calculations

After the stabilization of the well pressures, well control calculations should be performed before start implementing the killing procedures.
3.4 Before Establish Circulation

After completing all the required calculations and check all the results. Before establish the killing operation do the following check up.

- Be sure that every member of the crew knows exactly what his duties are before the kill operation begins.
- Eliminate all sources of ignition in the immediate vicinity of the rig and lines.
- Make sure your circulation system (including manifolds and pit) are lined-up correctly.
- Zero the stroke counters and make up to a note of the time.
- Ensure that a pumping rate is selected for which weighting up can be maintained.

4. Well Killing Methods

There are 5 methods to deal with an influx:

- Wait and Weight
- Driller’s Method
- Volumetric (Lubricant)
- Bullheading
- Stripping

Wait and weight method and driller’s method are the standard methods for killing the well while the three other methods will be applied in special cases where the standard methods can not be directly applied.

The following table illustrates the main differences between these Methods
### Killing Methods Comparison

**Table 3-2: Killing Methods Comparison**

<table>
<thead>
<tr>
<th>Concept</th>
<th>Wait &amp; Weight Method</th>
<th>Driller’s Method</th>
<th>Volumetric Method</th>
<th>Bullheading Method</th>
</tr>
</thead>
</table>
| **Concept** | One circulation with kill mud  
• Adjust the choke to follow the pressure step down table until kill mud reach the bit  
• Adjust the choke to keep drill pipe pressure constant until kill mud reach the surface | Two cycles to kill the Well:  
1st cycle with original mud  
• Adjust the choke to keep drill string pressure constant  
2nd cycle with kill mud  
• Adjust the choke to keep annulus pressure constant until kill mud reach the bit.  
• Adjust the choke to keep drill pipe pressure constant until kill mud reach the surface | Lubricate mud into the well and bleed off gas pressure equal to the pumped mud hydrostatic. Keep bottom hole pressure constant | Kill the well by pumping influx back to the formation |
| **Advantages** | Lower surface pressure  
Lower pressure at casing shoe  
Well subjected to pressure for least time | Fast displacement of the kick from the hole  
Earlier circulation reduces the risk of stuck pipe  
Influx displaced from the well even if weighting material not available  
Avoid need to initiate a volumetric control during the waiting period | Help in reducing surface pressure during stripping operation | No gas release from the surface |
<table>
<thead>
<tr>
<th>Preferred Method</th>
<th>Wait &amp; Weight Method</th>
<th>Driller’s Method</th>
<th>Volumetric Method</th>
<th>Bullheading Method</th>
</tr>
</thead>
<tbody>
<tr>
<td>• When Influx contains gas High intensity (large underbalance) kick</td>
<td>• Insufficient stocks of weighting materials</td>
<td>• During any shut in period after the well has kicked</td>
<td>• When large influx has been taken</td>
<td></td>
</tr>
<tr>
<td>• When open hole section is too shallow so the annulus pressure may exceed the shoe leak off pressure</td>
<td>• Mud system does not allow increasing density</td>
<td>• If the pumps are inoperative</td>
<td>• When displacement by conventional methods would result in an excessive volume of gas at surface</td>
<td></td>
</tr>
<tr>
<td>• When casing shoe is weak</td>
<td>• There is doubt about required kill mud weight</td>
<td>• Washout in the drillstring</td>
<td>• If the influx is suspected to contain an unacceptable level of H₂S and can not be handled safely by rig personnel and equipment</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Rapid Increase of surface pressure indicates the influx is rising rapidly in the annulus</td>
<td>• Pipe far away from the bottom</td>
<td>• Drillstring Off Bottom and could not strip back to bottom</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• The influx result from swabbing</td>
<td>• Bit nozzles plugged</td>
<td>• No pipe in the hole</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>• No string in hole</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
5. **Wait and Weight Method**

The Wait and Weight Method accomplishes the kill operation in one complete circulation. It requires weight up of the mud after the well is shut in, followed by circulation with the kill mud.

### 5.1 Pre-killing Calculations

Before start killing operations a kill sheet should be filled completely, the following equations should be used for the calculations.

1. **Hydrostatic Pressure (psi)**
   
   \[
   \text{Hydrostatic Pressure (psi)} = \frac{\text{Mud Weight (pcf)} \times \text{True vertical Depth, TVD (ft)}}{144}
   \]

2. **Formation Pressure (psi)**
   
   \[
   \text{Formation Pressure (psi)} = \text{Hydrostatic Pressure in Drill Pipe (psi)} + \text{SIDPP (psi)}
   \]

3. **Kill Mud Density (pcf)**
   
   \[
   \text{Kill Mud Density (pcf)} = \frac{\text{SIDPP (psi)} \times 144}{\text{TVD (ft)}} + \text{Original Mud Weight (pcf)}
   \]

4. **Equivalent Mud Weight, EMW (pcf)**
   
   \[
   \text{Equivalent Mud Weight, EMW (pcf)} = \frac{\text{Leak Off Pressure (psi)} \times 144}{\text{Casing Shoe TVD (ft)}} + \text{LeakOff Mud Wt (pcf)}
   \]

5. **Maximum Allowable Surface Pressure, MAASP**
   
   \[
   \text{Maximum Allowable Surface Pressure, MAASP} = \left(\text{Max Allowable Mud Density (pcf)} - \text{Current Mud Density (pcf)}\right) \times 0.007 \times \text{Shoe TVD (ft)}
   \]

6. **Initial Circulating Pressure (psi)**
   
   \[
   \text{Initial Circulating Pressure (psi)} = \text{SIDPP (psi)} + \text{Slow Pump Rate Pressure, SPRP (psi)}
   \]

7. **Final Circulating Pressure (psi)**
   
   \[
   \text{Final Circulating Pressure (psi)} = \text{SPRP (psi)} \times \frac{\text{Kill Mud Wt (pcf)}}{\text{Original Mud Wt (pcf)}}
   \]
8. Equivalent Circulating Density, ECD (pcf)
\[ ECD = \frac{144 \times \text{Annular Pressure Loss (psi)}}{\text{TVD Bit (ft)}} + \text{Mud Wt (pcf)} \]

9. Height of Influx (ft)
\[ \text{Height of Influx (ft)} = \frac{[\text{Pit Gain (bbl)}]}{\text{Annulus Capacity Factor (bbl/ft)}} \]

10. Pressure Gradient of Influx (psi/ft) Bit on Bottom
\[ \text{Pressure Gradient of Influx (psi/ft)} = \frac{\text{Pressure Gradient of Mud (psi/ft)} - \left( \frac{\text{SI CP (psi) - SIDPP (psi)}}{\text{Height of Influx (ft)}} \right)}{\text{Height of Influx (ft)}} \]

11. Rate of Kick Rise (ft/hr) (Well Shut-In)
\[ \text{Rate of Kick Rise (ft/hr)} = \frac{\text{Change in SI CP (psi) x 144}}{\text{Mud Wt (pcf) x Elapsed Time for Change in SI CP (hr)}} \]

5.2 Prior to Starting Circulation

- Be sure that every member of the crew knows exactly what his duties are before the kill operation begins.
- Eliminate sources of ignition in the vicinity of the rig and lines.
- Make sure the circulation system (including manifolds and pit) are lined up correctly.
Abu Dhabi Company for Onshore Oil Operations

**Well Killing Sheet**

**Wait and Weight Method**

<table>
<thead>
<tr>
<th>FORMATION STRENGTH DATA:</th>
<th>CURRENT WELL DATA:</th>
</tr>
</thead>
<tbody>
<tr>
<td>SURFACE LEAK-OFF PRESSURE FORM</td>
<td>DRILLING FLUID DATA:</td>
</tr>
<tr>
<td>FORMATION STRENGTH TEST</td>
<td>DENSITY</td>
</tr>
<tr>
<td>(A) PSI</td>
<td></td>
</tr>
<tr>
<td>DRILLING FLUID Wt. AT TEST</td>
<td>GRADIENT</td>
</tr>
<tr>
<td>(B) PCF</td>
<td></td>
</tr>
<tr>
<td>MAX. ALLOWABLE DRILLING FLUID WEIGHT =</td>
<td></td>
</tr>
<tr>
<td>( \frac{(B) \times 144}{\text{SHOE T.V. DEPTH}} )</td>
<td>(C) PCF</td>
</tr>
<tr>
<td>INITIAL MAASP = ( \frac{(C) - \text{CURR. Wt.}}{\text{SHOE T.V. DEPTH}} \times 144 )</td>
<td>PSI</td>
</tr>
</tbody>
</table>

**PUMP NO. 1 DISPL.**

<table>
<thead>
<tr>
<th>PUMP NO. 2 DISPL.</th>
</tr>
</thead>
<tbody>
<tr>
<td>BBL/STROKE</td>
</tr>
</tbody>
</table>

**SLOW PUMP RATE DATA:**

<table>
<thead>
<tr>
<th>(PL) DYNAMIC PRESSURE LOSS</th>
<th>PUMP NO. 1</th>
<th>PUMP NO. 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>SPM</td>
<td>PSI</td>
<td>PSI</td>
</tr>
<tr>
<td>SPM</td>
<td>PSI</td>
<td>PSI</td>
</tr>
</tbody>
</table>

**PRE-RECORDED VOLUME DATA**

<table>
<thead>
<tr>
<th>LENGTH FT</th>
<th>CAPACITY BBL/FT</th>
<th>VOLUME BBL</th>
<th>PUMP STORKES STKS</th>
<th>TIME MIN</th>
</tr>
</thead>
<tbody>
<tr>
<td>DP-SURFACE TO KOP</td>
<td>X = (L)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>DP – KOP TO EOB</td>
<td>X = + (M)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>DP – EOB TO BHA</td>
<td>X = + (N1)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>HWDP</td>
<td>X = + (N2)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>DRILL COLLAR</td>
<td>X = + (N3)</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**DRILL STRING VOLUME**

<table>
<thead>
<tr>
<th>(D) BBL</th>
<th>MIN</th>
</tr>
</thead>
<tbody>
<tr>
<td>DC x OPEN HOLE</td>
<td>X =</td>
</tr>
<tr>
<td>DP/HWDP x OPEN HOLE</td>
<td>X = +</td>
</tr>
</tbody>
</table>

**OPEN HOLE VOLUME**

<table>
<thead>
<tr>
<th>(F) BBL</th>
<th>STKS</th>
<th>MIN</th>
</tr>
</thead>
<tbody>
<tr>
<td>DP X CASING</td>
<td>x = (G) +</td>
<td>STKS</td>
</tr>
</tbody>
</table>

**TOTAL ANNULUS VOLUME**

<table>
<thead>
<tr>
<th>(F+G)=(H) BBL</th>
<th>STKS</th>
<th>MIN</th>
</tr>
</thead>
</table>

**TOTAL WELL SYSTEM VOLUME**

<table>
<thead>
<tr>
<th>(D+H)=(I) BBL</th>
<th>STKS</th>
<th>MIN</th>
</tr>
</thead>
</table>

**SURFACE LINES VOLUME**

<table>
<thead>
<tr>
<th>(K) BBL</th>
<th>STKS</th>
<th>MIN</th>
</tr>
</thead>
</table>

**ACTIVE SURFACE VOLUME**

| (J) BBL | |
|---------||

**TOTAL ACTIVE FLUID SYSTEM**

| ((K+J) BBL | |
|------------||
### Abu Dhabi Company for Onshore Oil Operations

#### Well Killing Sheet

**Wait and Weight Method**

<table>
<thead>
<tr>
<th>Well:</th>
<th>Rig:</th>
<th>Date:</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
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</tr>
</tbody>
</table>

**Kick Data:**

- SIDPP: 
- SICP: 
- PIT GAIN: 

**Kill Fluid Weight (KMW):**

\[
\text{CURRENT DRILLING FLUID WEIGHT} + \text{SIDPP} \times 144 / \text{TVD} = \text{PCF} 
\]

**Initial Circulating Pressure (ICP):**

\[
\text{DYNAMIC PRESSURE LOSS} + \text{SIDPP} = \text{psi} 
\]

**Final Circulating Pressure (FCP):**

\[
\text{KILL FLUID WEIGHT} \times \text{DYNAMIC PRESSURE LOSS} = \text{psi} 
\]

**Dynamic Pressure Loss at KOP (O):**

\[
\text{PL} + \left[\text{FCP} \times \text{TDMW} \times \text{KOPMW} / \text{PL} \times (\text{FCP} - \text{PL})\right] = \text{psi} 
\]

**Remaining SIDPP at KOP (P):**

\[
\text{SIDPP} - \left[\left(\text{KMW} - \text{OMW}\right) \times \text{KOPTVD}\right] / 144 = \text{psi} 
\]

**Circulating Pressure at KOP (KOP CP):**

\[
\text{ICP} - \text{KOP CP} = \text{psi} 
\]

**Dynamic Pressure Loss at EOB (R):**

\[
\text{PL} + \left[\text{EOBMW} \times \text{TDMW} \times \text{EOBMW} / \text{PL} \times (\text{EOBMW} - \text{FCP})\right] = \text{psi} 
\]

**Remaining SIDPP at EOB (S):**

\[
\text{SIDPP} - \left[\left(\text{KMW} - \text{OMW}\right) \times \text{EOBTVD}\right] / 144 = \text{psi} 
\]

**Circulating Pressure at EOB (EOB CP):**

\[
\text{ICP} - \text{EOB CP} = \text{psi} 
\]

**Other Calculations:**

\[
(T) = \text{ICP} - \text{KOP CP} = \text{psi} 
\]

\[
(U) = \text{KOP CP} - \text{EOB CP} = \text{psi} 
\]

\[
(w) = \text{EOB CP} - \text{FCP} = \text{psi} 
\]

---

S.G. Rev-0/05

HDO(S/N/E): Date :

HDO(BU/BB): Date :

DM: Date :

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Printed on: 02/03/2005
## Abu Dhabi Company for Onshore Oil Operations
### Well Killing Sheet
#### Wait and Weight Method

<table>
<thead>
<tr>
<th>Well:</th>
<th>Rig:</th>
<th>Date:</th>
</tr>
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</table>

<table>
<thead>
<tr>
<th>Pressure (psi)</th>
<th>Strokes (strk)</th>
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<tbody>
<tr>
<td></td>
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**S.G.**
Rev-0/05

**HDO(S/N/E):**
- Date:

**HDO(BU/BB):**
- Date:

**DM:**
- Date:

**Page:**
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**Printed on:** 02/03/2005
5.3 Killing Procedure

After recording the Shut-in Drill pipe pressure and Shut-in Casing pressure, fill out the kill sheet completely then proceed in displacing the kick as follow:

- bring the pump up to kill speed
  - Line up the pump to the drillpipe and route returns through the choke manifold to the poor boy degasser.
  - Zero the stroke counter on the choke panel.
  - Open the remote operated choke at the same time as the pump is started on the hole.
  - Maintain the choke pressure equal to the original shut-in casing pressure as the pump is slowly brought up to speed. This may take 1/2 to 1 minute.
  - Once the pump is up to speed, record the initial circulating pressure (ICP)

**If the actual initial circulating pressure is considerably different from the calculated value, stop the pump, shut in the well, and investigate the cause.**

If the actual initial circulating pressure is equal to, or reasonably close to the calculated value, continue the displacement and adjust the standpipe pressure schedule accordingly.

Any marginal difference between the actual and calculated initial circulating pressure is most likely to be due to the fact that the SCR (Slow Circulating Rate) pressure used to calculate the initial circulating pressure was inaccurate. The actual SCR pressure, and hence the corrected final circulating pressure can be determined from the initial circulating pressure as follows:

\[ P_{scr} = ICP - SIDPP \]

The standpipe pressure schedule can therefore be corrected to take into account the adjusted circulating pressures.

- Circulate the influx from the well maintaining constant bottomhole pressure

As the drillpipe is displaced with kill mud, the standpipe pressure should be stepped down according to the standpipe pressure schedule. (The standpipe pressure will have a natural tendency to drop as the kill mud is displaced down the drillpipe.)
Once the drillpipe has been displaced to kill mud, the drillpipe pressure should be maintained at the final circulating pressure for the rest of the circulation.

The pit gain, drillpipe pressure, choke pressure and all other relevant information should be recorded during displacement.

As the influx is displaced up the hole, the drillpipe pressure will tend to drop as the influx expands. (This expansion will not occur if the influx is water or oil.) This effect will be especially marked if the influx contains a significant quantity of gas. The choke should therefore be adjusted to compensate for this.

As the influx is circulated from the well and mud is circulated to the choke, the choke pressure will begin to rise rapidly. The choke should therefore be opened to allow the choke pressure to drop sufficiently to maintain the final circulating pressure on the drillpipe, and hence maintain constant bottomhole pressure.

Once the hole has been circulated to kill mud, the pump should be stopped, the well shut in, and the casing and drillpipe checked for pressure. There should be no pressure on either the casing or the drillpipe. However, if there is still some pressure on the casing, circulation should be restarted to clear the contaminated mud from the annulus and mud weight must be monitored.

Two or three circulations may be required especially in horizontal hole.
6. Driller’s Method

The Driller’s Method is a two complete circulation method. The kick is circulated out of the hole by the first circulation with the original mud. The second circulation is carried out with the weighted mud to kill the well.

Prior to the first circulation, fill the kill sheet then proceed in the killing operation as follow:

6.1 First Circulation

- Bring the pump up to speed for the first complete circulation:
  - Line up the pump to the drillpipe and route returns through the choke manifold to the mud gas separator.
  - Set the stroke counter on the remote choke panel to zero.
  - Open the remotely operated choke at the same time as the pump is slowly brought up to speed. Consider stroking the drillstring up at this point.
  - Maintain the choke pressure equal to the original shut in casing pressure as the pump is slowly brought up to speed. This may take 1/2 to 1 minute.
  - Once the pump is up to speed record the initial circulating pressure. If the actual initial circulating pressure is considerably different from the calculated value, stop the pump, shut in the well and investigate the cause.

If the actual initial circulating pressure is equal to, or reasonably close to, the calculated value, continue the displacement, holding the standpipe pressure at the value recorded when the pump was first brought up to speed.

Any marginal difference between the actual and calculated initial circulating pressure is most likely to be due to the fact that the SCR pressure used to calculate the initial circulating pressure was inaccurate. The actual SCR pressure can be determined from the initial circulating pressure as follows:

$$ P_{scr} = ICP - P_{dp} $$

This adjusted value for the SCR pressure should be used for estimating the circulating pressures for the second complete circulation.

- Circulate the influx from the well maintaining constant bottomhole pressure by adjusting the choke to keep the drill pipe pressure constant.
Influx behavior during circulation will be similar to the Wait and Weight Method requiring similar choke manipulation.

Choke pressures will inevitably be higher than if the Wait and Weight Method had been used. These higher pressures will be reflected downhole, causing greater stress in the open hole.

Once the influx has been displaced from the hole, the shut in drillpipe and shut in casing pressure should be equal. If the casing pressure is higher than the drillpipe pressure, this is evidence that there is still some kick fluid in the annulus, or the mud weights are out of balance.

### 6.2 Second Circulation

After the mud has been properly weighted up and prior to circulating kill mud into the hole, perform the following calculations.

- Determine the circulation rate for the second circulation.
- Initial circulating pressure will be the same as for the first circulation.
- Calculate the final circulating pressure.

The following can be used as a guide for the procedure of Second circulation:

- Bring the pump up to speed for the second complete circulation:
  - Establish the desired pump rate by holding the shut-in casing pressure constant while bringing the pump up to the kill rate.
  - Zero the stroke counter on the choke panel.

The initial circulating pressure should be the same as the standpipe pressure during the first complete circulation. If this is the case, continue the displacement and adjust the standpipe pressure schedule accordingly.

If the initial circulating pressure has changed considerably, stop the pump, shut in the well, and investigate the cause.

- Circulate the hole to kill mud maintaining constant bottomhole pressure.

As the drillpipe is displaced with kill mud, adjust the choke so that the casing pressure remains constant at the shut in value it had before start of the second circulation.

Once the drillpipe has been displaced to kill mud, the final drillpipe circulating pressure is held constant by manipulating the choke.

As kill mud is circulated up the annulus, the drillpipe pressure will tend to increase. The choke should be adjusted to ensure that the drillpipe pressure is maintained at the final circulating pressure; thereby ensuring constant bottomhole pressure.
When the kill mud is returned, stop pumps, shut in the well and check for well pressure.

Once the well has been killed, a flowcheck on the choke line return should be carried out before the rams are opened.

If this flowcheck indicates no flow, the rams should be opened and a further flowcheck on the annulus carried out.
Abu Dhabi Company for Onshore Oil Operations

Well Killing Sheet
Driller’s Method

<table>
<thead>
<tr>
<th>Well:</th>
<th>Rig:</th>
<th>Date:</th>
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**FORMATION STRENGTH DATA:**

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<thead>
<tr>
<th>FORMATION STRENGTH TEST</th>
<th>PSI</th>
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<tbody>
<tr>
<td>(A)</td>
<td></td>
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</tbody>
</table>

**MAX. ALLOWABLE DRILLING FLUID DENSITY:**

\[
(B + \frac{(A \times 144)}{SHOE \ T.V. \ DEPTH}) = (C) \text{ PCF}
\]

**INITIAL MAASP:**

\[
144 \times ((C - CURR. DENS.) \times SHOE \ T.V. \ DEPTH) = (C) \text{ PSI}
\]

**CURRENT WELL DATA:**

<table>
<thead>
<tr>
<th>DRILLING FLUID DATA:</th>
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<tbody>
<tr>
<td>DENSITY</td>
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<tr>
<td>GRADIENT</td>
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**DEViation DATA:**

<table>
<thead>
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<th>KOP M.D.</th>
<th>FT</th>
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<tbody>
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<td>KOP T.V.D.</td>
<td>FT</td>
</tr>
<tr>
<td>EOB M.D.</td>
<td>FT</td>
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<tr>
<td>EOB T.V.D.</td>
<td>FT</td>
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**CASING SHOE DATA:**

<table>
<thead>
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<tbody>
<tr>
<td>M. DEPTH</td>
<td>FT</td>
</tr>
<tr>
<td>T.V. DEPTH</td>
<td>FT</td>
</tr>
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</table>

**HOLE DATA:**

<table>
<thead>
<tr>
<th>SIZE</th>
<th>FT</th>
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</thead>
<tbody>
<tr>
<td>M. DEPTH</td>
<td>FT</td>
</tr>
<tr>
<td>T.V. DEPTH</td>
<td>FT</td>
</tr>
</tbody>
</table>

**PRE-RECORDED VOLUME DATA:**

<table>
<thead>
<tr>
<th>LENGTH FT</th>
<th>CAPACITY BBL/FT</th>
<th>VOLUME BBL</th>
<th>PUMP STORKES stks</th>
<th>TIME Minutes</th>
</tr>
</thead>
<tbody>
<tr>
<td>DP-SURFACE TO KOP</td>
<td>X = (L)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>DP - KOP TO EOB</td>
<td>X = + (M)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>DP - EOB TO BHA</td>
<td>X = + (N1)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>HEVI WALL DRILL PIPE</td>
<td>X = + (N2)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>DRILL COLLAR</td>
<td>X = + (N3)</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**DRILL STRING VOLUME:**

\[
(D) = \text{BBL}
\]

**OPEN HOLE VOLUME:**

\[
(F) = \text{BBL}
\]

**TOTAL ANNULUS VOLUME:**

\[
(G) = \text{STKS}
\]

**TOTAL WELL SYSTEM VOLUME:**

\[
(I) = \text{STKS}
\]

**SURFACE LINES VOLUME:**

\[
(K) = \text{STKS}
\]

**ACTIVE SURFACE VOLUME:**

\[
(J) = \text{BBL}
\]

**TOTAL ACTIVE FLUID SYSTEM:**

\[
(I+K+J) = \text{BBL}
\]
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Well Killing Sheet
Driller’s Method

<table>
<thead>
<tr>
<th>Well:</th>
<th>Rig:</th>
<th>Date:</th>
</tr>
</thead>
</table>

KICK DATA:

<table>
<thead>
<tr>
<th>SIDPP</th>
<th>SICP</th>
<th>PIT GAIN</th>
<th>KILL FLUID WEIGHT</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>CURRENT DRILLING FLUID DENSITY + $\frac{\text{SIDDP} \times 144}{\text{TVD}}$ = .</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>$\text{........} + \text{........} \times 144$ = $\text{........ pcf}$</td>
</tr>
</tbody>
</table>

FIRST CIRCULATION

<table>
<thead>
<tr>
<th>CIRCULATING PRESSURE</th>
<th>DYNAMIC PRESSURE LOSS + SIDPP</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$\text{...............} + \text{...............} = \text{............... psi}$</td>
</tr>
</tbody>
</table>

SECOND CIRCULATION

<table>
<thead>
<tr>
<th>INITIAL CIRC. PRESS.</th>
<th>DYNAMIC PRESSURE LOSS + SIDPP</th>
</tr>
</thead>
<tbody>
<tr>
<td>(from surface to Bit)</td>
<td>$\text{...............} + \text{...............} = \text{............... psi}$</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>FINAL CIRCULATING PRESSURE (from Bit to Surface)</th>
<th>KILL FLUID WEIGHT $\times$ DYNAMIC PRESSURE LOSS</th>
</tr>
</thead>
<tbody>
<tr>
<td>FCP</td>
<td>$\text{...............} \times \text{...............} = \text{............... psi}$</td>
</tr>
<tr>
<td></td>
<td>$\text{...............}$</td>
</tr>
</tbody>
</table>

S.G.   | HDO(S/N/E) : | HDO(BU/BB) : | DM : | Page |
---|--------------|--------------|------|------|
Rev-0/05 | Date : | Date : | Date : | 3-32 |

Printed on: 02/03/2005
7. **Volumetric Method**

In some well control situation, special problems may arise that complicate the application of routine methods of well control. One of these problems is not being able to circulate an influx out of the wellbore. This maybe due to several things, such as plugged bit or drill pipe, drill pipe being far above the influx, as in a kick taken while tripping; or pipe being out of the hole completely. When one of these problems occurs; the well cannot be circulated with kill mud until corrective measures have been taken and the ability to circulate out the influx is regained which could require quite some time.

Monitoring the casing pressure while initiating corrective procedures will dictate the method of controlling the well. If the casing pressure does not increase above the original shut-in pressure, a saltwater kick is most likely indicated. Since there is less density differential between salt water and mud than between gas and mud, the salt water will migrate much slower than gas. Thus; the shut-in casing pressure will remain relatively constant and the only consideration is to leave the well shut in until it can be killed. However, if the casing pressure increase above the original shut-in pressure, a gas kick is indicated. The expansion characteristics of gas coupled with the density differential between gas and mud which cause the gas to migrate up the hole, dictate the use of the volumetric control method.

### 7.1 Basic Volumetric Control Principles

There are three basic principles which volumetric method based on:

#### 7.1.1 First Basic Principle - Boyle’s Law

Boyle’s Law states that the pressure of a gas is directly related to its volume.

Boyle’s Law is written as:

\[ P_1V_1 = P_2V_2 \]

Where:

- \( P_1 \) = Pressure in gas at condition 1
- \( V_1 \) = Volume of gas at condition 1
- \( P_2 \) = Pressure in gas at condition 2
- \( V_2 \) = Volume of gas at condition 2

#### 7.1.2 Second Basic Principle - Hydrostatic Pressure

The rising gas bubble can be treated as a surface pressure with respect to the mud below it. Any time the gas bubble rises by one foot in the annulus, there will be one additional foot of mud below the gas bubble. The additional foot of mud below the gas bubble increases the hydrostatic pressure of the mud below the gas bubble, which increases the bottomhole pressure by a like amount according to the following formula:
Bottomhole Pressure = Hydrostatic Pressure + Surface Pressure

If we bleed mud from the annulus in order to lower the pressure in the gas bubble, then we naturally reduce the volume of mud in the annulus, and therefore, the hydrostatic pressure as well. When we bleed the mud from the annulus, it is very important that we do it in a way that holds the casing pressure (surface pressure) constant. From the above equation, it is clear that if we bleed mud from the annulus (lower the hydrostatic pressure) while holding the same casing pressure (surface pressure constant), then the bottomhole pressure will also decrease.

In order to keep BHP constant bleed off a volume of mud which causes a reduction in the hydrostatic pressure equal to the rise in casing pressure caused by the migrating gas. It is for this reason that we must measure the amount of mud bled-off from the annulus and equate that volume to a reduction in hydrostatic pressure.

7.1.3 Third Basic Principle - Volume and Height

Annulus capacity factors can be calculated with the following formula:

\[ ACF = \frac{OD^2 - ID^2}{1029.4} \]

Where:
- ACF = Annulus Capacity Factor (bbl/ft)
- OD = Outside Diameter of Annular Space (in)
- ID = Inside Diameter of Annular Space (in)

7.2 Description of the Method

The volumetric control is a method of controlling the bottomhole pressure until provisions can be made to circulate or bullhead kill mud into the well.

7.2.1 Step 1 - Calculations

There are three calculations which need to be performed before a volumetric control procedure can be executed.

- Safety Factor
- Pressure Increment
- Mud Increment.

Safety factor

The safety factor is an increase in the bottomhole pressure which we allow to occur naturally as gas migrates up the annulus. By allowing
the gas bubble to rise in the annulus; we are allowing the bottomhole pressure to increase. It is important that we allow the bottomhole pressure to increase to a value which is well above the formation pressure to insure that we don't go underbalanced when we bleed mud from the annulus in later steps. An appropriate value for the safety factor is in the range of 200 psi in most cases. Depending on the depth, angle and fluid in the well, it may take several hours for the gas bubble to rise sufficiently to increase the casing pressure by 200 psi.

Sometimes, depending on how close the shoe is to exceeding its fracture pressure under initial shut-in conditions, it will be advisable to select a safety factor smaller than 200 psi. Any increase in the bottomhole pressure will be reflected as an equal increase in the shoe pressure as well. If the shoe is close to its fracture pressure, then the safety factor will have to be appropriately reduced. If you calculate that a 200 psi safety factor will break the shoe down, then a 100 psi safety factor would be more suitable.

**Pressure Increment**

The pressure increment is the reduction in hydrostatic pressure which occurs each time we bleed a given volume of mud from the annulus. The Drilling supervisor should select a pressure increment which produces a reduction in hydrostatic pressure equal to one-third of the value of the initial safety factor (rounded to the nearest 10 psi). For example, if a 150 psi safety factor was chosen, then the pressure increment should produce a reduction in hydrostatic pressure of 50 psi (i.e., one-third of 150 psi).

\[
\text{Pressure Increment} = \frac{\text{Safety Factor}}{3}
\]

**Mud Increment**

The mud increment is the volume of mud which must be bled from the annulus in order to reduce the annular hydrostatic pressure by the amount of the pressure increment determined above. The mud increment can be calculated with the equation given to the right. It is very important that some means be available to measure the small volumes of mud which are bled off from the annulus.

\[
\text{Mud Increment} = \frac{\text{Pressure Increment (psi)}}{\text{Annulus Capacity Factor (bbl/ft)}} \times \frac{\text{Mud Weight (pcf)}}{0.007}
\]

Where:

- \( \text{PI} \) = Pressure Increment (psi)
- \( \text{ACF} \) = Annulus Capacity Factor (bbl/ft)
- \( \text{MW} \) = Mud Weight (pcf)
7.2.2 Step 2 - Allow Casing Pressure to Increase to Establish Safety Factor

After the calculations are completed, the next step in Volumetric Control is to wait for the gas bubble to migrate up the hole and cause an increase in the shut-in casing pressure. We should allow the gas bubble to rise until the casing pressure has increased by an amount equal to the safety factor. No mud has been bled off from the annulus, so the hydrostatic pressure of the mud has not changed since the well was first shut in.

While Gas Bubble Migrates

\[ \text{Bottomhole Pressure} = \text{Hydrostatic Pressure} + \text{Surface Pressure} \]

(Goes Up) \quad (Stays the Same) \quad (Goes Up)

At this point, the bottomhole pressure has also increased by the amount of the safety factor and the well should be safely overbalanced.

7.2.3 Step 3 - Hold Casing Pressure Constant by Bleeding Off the Mud Increment

After the safety factor overbalance is applied to the well, the first mud increment can be bled from the well. The manner in which the mud is bled-off from the annulus is very important--it must be bled in such a way that the casing pressure remains constant throughout the entire bleeding. This is done to insure that the bottomhole pressure is reduced only by a loss in the mud hydrostatic pressure, and not by an additional loss in surface pressure. During the bleeding process, the hydrostatic pressure is reduced by the pressure increment while the surface pressure is held the same, so the bottomhole pressure is also reduced by the pressure increment.

While bleeding off mud from the annulus

\[ \text{Bottomhole Pressure} = \text{Hydrostatic Pressure} + \text{Surface Pressure} \]

(Goes Down) \quad (Goes Down) \quad (Stay the same)

Each time we bleed mud from the annulus, the gas bubble expands to fill the volume vacated by the mud. As the gas bubble expands, the pressure in the bubble decreases according to, Boyle's Law.

7.2.4 Step 4- Wait for the Casing Pressure to Rise as the Gas Bubble Migrates

Each bleeding of mud from the annulus reduces the bottomhole pressure by the amount of the pressure increment. This decreases our
safety factor overbalance. In order to get the full value of overbalance back on the well, we simply wait for the gas bubble to migrate up the annulus. As the gas bubble migrates, the surface pressure and bottomhole pressure increase just as when the safety factor was-applied. We wait for the gas bubble to rise’ until the surface casing pressure has increased by an amount equal to the pressure increment. At this point, we have also increased bottomhole pressure by the amount of the pressure increment, and the well is back at full overbalance.

7.2.5 Step 5 – Hold Casing Pressure Constant by Bleeding Mud From the Annulus

Once we have our full overbalance back on the well; we can safely bleed another mud increment from the annulus. As with the first bleeding, this step is accomplished while holding casing pressure constant. This reduces the bottomhole pressure by the amount of the pressure increment because a like amount of mud hydrostatic pressure has been bled from the well. This has also caused the gas bubble to expand by the volume of the mud increment.

7.2.6 Step 6

Repeat steps 4 & 5 until the gas bubble reach the surface

7.2.7 Step 7 - Lubricate Mud into the Well

The casing pressure should stop increasing after the gas has reached the surface. The well is stable at this point, but in most cases, you will want to bleed the gas from the well and replace it with mud before attempting further well work. This step involves bleeding gas from the well to reduce the casing pressure by a predetermined increment. Then, a measured volume of mud should be pumped into the well to increase the hydrostatic pressure in the annulus by the amount of surface pressure which was lost when the gas was first bled off. These steps should be repeated until gas can no longer be bled from the well.

The Lubricate and Bleed procedure is listed in the following steps.

1- Calculations

Calculate the hydrostatic pressure that will be exerted by 1 barrel of mud.

2- Lubricate

Slowly pump a given volume of mud into the well. The amount chosen will depend on many different well conditions & may change
throughout the procedure. The rise in surface pressure can be calculated by applying Boyle's law of $P_1V_1 = P_2V_2$ and realizing that for every barrel of mud pumped into the well the bubble size decreases by 1 barrel.

3 - Wait

Allow the gas to migrate back to the surface. This step could take quite some time and is dependent on a number of factors such as mud weight and viscosity.

4 - Bleed

Bleed gas from the well until the surface pressure is reduced by an amount equal to the hydrostatic pressure of the mud pumped in. It is very important to bleed only gas. If at any time during the procedure mud reaches the surface and starts bleeding, the well should be shut in and the gas allowed migrating.

5 - Repeat Previous Steps

Repeat steps 2 through 4 until all of the gas has been bled off or a desired surface pressure has been reached.
Abu Dhabi Company for Onshore Oil Operations

Volumetric Method Worksheet

Equations:

\[ P_1 V_1 = P_2 V_2 \]

\[ ACF = \frac{OD^2 - ID^2}{1029.4} \]

\[ \text{Mud Increment} = \frac{P_l \times CF}{MW \times 0.007} \]

Notes:

- ...
- ...
- ...
- ...
- ...


<table>
<thead>
<tr>
<th>Casing Pressure (psi)</th>
<th>Mud Removed (bbl)</th>
<th>Bubble Volume (bbl)</th>
<th>Bubble Pressure (bbl)</th>
<th>Top of Bubble (ft)</th>
<th>Bubble Length (ft)</th>
<th>Bottom Hole Pressure (psi)</th>
</tr>
</thead>
<tbody>
<tr>
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</table>
8. Bullheading

8.1 General

Bullheading is a technique that may be used in certain circumstances during drilling operations to pump an influx back into the formation.

A major concern with this technique is that it may result in fracturing any exposed formation.

Bullheading is, however a relatively common method of killing a well during workover operations when there is adequate reservoir permeability.

8.2 When to Bullhead

During operations, bullheading may be considered in the following situations:

- When a very large influx has been taken.
- When displacement of the influx by conventional methods may cause excessive surface pressures.
- When displacement of the influx by conventional methods would result in an excessive volume of gas at surface conditions.
- If the influx is suspected to contain an unacceptable level of H₂S and can not be handled safely by rig personnel and equipment.
- When a kick is taken with the pipe off bottom and it is not considered feasible to strip back to bottom.
- When an influx is taken with no pipe in the hole.
- When an influx is taken with no possibility of circulation.
- To reduce surface pressures prior to implementing further well control operations

8.3 Factors affects on Bullheading

Bullheading during drilling operations will be implemented when standard well control techniques are considered inappropriate. During such situations, it is unlikely that accurate information is available regarding the feasibility of bullheading. In most cases therefore, the likelihood of successfully bullheading an influx will not be known until it is attempted. However, the major factors that will determine the feasibility of bullheading include the following:

- The characteristics of the open hole.
• The rated pressure of the well control equipment and the casing (making allowance for wear and deterioration).
• Rated pressure, reliability and output of available pumping equipment.
• The type of influx and the relative permeability of the formation.
• The quality of the filter cake at the permeable formation.
• The consequences of fracturing a section of the open hole.
• The position of the influx in the hole.
• Displacement rate required in larger hole sizes.

8.4 Procedure

In general, bullheading procedures can only be drawn up bearing in mind the particular circumstances at the rig site. For example, there may be situations in which it is considered necessary to cause a fracture downhole to bullhead away an influx containing H₂S. In another situation with shallow casing set, it may be considered totally unacceptable to cause a fracture in the open hole. Consideration should always be given to monitoring annulus pressure and applying backup pressure in the annulus to reduce differential pressures.

During a workover operation a procedure for bullheading will be drawn up along the following lines:

• Calculate surface pressures that will cause formation fracture during bullheading. Also calculate the tubing burst pressures as well as casing burst (to cover the possibility of tubing failure during the operation).
• Calculate static tubing head pressure during bullheading.
• Slowly pump kill fluid down the tubing. Monitor pump and casing pressure during the operation.
9. Stripping

9.1 General

Stripping is a technique that can be used to move the drillstring through the Blowout Preventer (BOP) stack when the well is under pressure. Stripping places high levels of stress on the BOPs and the closing unit, and requires a particularly high level of co-ordination within the drill crew.

It is recommended that an operational plan is developed regarding stripping procedure. This paragraph is intended to aid in the drawing up of this operational plan and as such the following are proposed as the most important considerations:

- How to move the tool joint through the BOP.
- Wear on BOP elements and the control unit.
- The level of redundancy in the BOP and the control system.
- Wellbore pressures in relation to the maximum allowable pressure for equipment and the formation
- The monitoring of pressure and fluid volumes.
- The organization and supervision of the drill crew.
- Controlling increases in wellbore pressure due to surge pressure.
- The condition of the drillpipe (Drillpipe rubbers should be removed and any burrs on tool joints smoothed out.).
- The possibility of sticking the pipe.
- The control of influx migration.
- Manufacturers’ information regarding minimum closing pressures for annular preventers. (This information should be available at the rig site.).

9.2 Checklist for Stripping

- Have the calculations been completed and verified by the Rig Manager and Drilling Supervisor?
- Has one person been designated to supervise the stripping operation?
- Are the BOP space-out figures readily available?
- Are signs available to hang on the BOP function buttons?
9.3 Guidelines to Responsibilities for Stripping

Table 3-3: Guidelines to responsibilities for stripping

<table>
<thead>
<tr>
<th>Drilling Supervisor</th>
<th>Is in charge of the entire stripping operation.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rig Manager/</td>
<td>He will delegate positions and allocate tasks to all crew members.</td>
</tr>
<tr>
<td>Assistant Rig Manager</td>
<td>He will complete the necessary calculations in consultation with the Drilling Supervisor.</td>
</tr>
<tr>
<td></td>
<td>Depending on the criticality of the operation and available manpower, the Rig Manager may operate the</td>
</tr>
<tr>
<td>Driller</td>
<td>Will operate the drawworks and BOP panel.</td>
</tr>
<tr>
<td>Assistant Driller</td>
<td>Will ensure correct equipment line-up and may be assigned to operate the choke under the supervision of the Rig Manager (AD must be well control certified).</td>
</tr>
<tr>
<td>Derrickman</td>
<td>Will be in the derrick for running pipe.</td>
</tr>
<tr>
<td>Roughnecks</td>
<td>Will be on the rig floor and one man assigned to the trip / stripping tank.</td>
</tr>
<tr>
<td>Roustabouts</td>
<td>Will be at the flowline to observe for excessive leakage past the BOPs. Also assigned to mix mud as required.</td>
</tr>
<tr>
<td>Cementer</td>
<td>Will stand by as required for pumping purposes.</td>
</tr>
<tr>
<td>Mud Engineer</td>
<td>Will be at the mud pits and have responsibility for the mud mixing, condition and properties.</td>
</tr>
</tbody>
</table>

There are three basic stripping techniques
9.3.1 Volumetric Strip

This allows for any gas expansion and the effect of the drillstring entering the influx and will normally result in lowest surface and bottomhole pressures. See Figure 3-1.

9.3.2 Strip using closed end displacement

Only Useful if there is a large hole volume, only a few stands to strip and gas expansion is not an issue.

9.3.3 Dynamic Volumetric Strip

![Flowchart for Dynamic Volumetric Strip]

Figure 3-1: A Guide to Volumetric Stripping
Surface Pressure Changes during Stripping

Figure 3-2: A Guide to interpretation of surface pressure changes during standard stripping
9.4 Monitoring Well Pressures and Fluid Volumes

During stripping operations, a constant bottomhole pressure is maintained by carefully controlling the surface pressure and monitoring the volume of mud bled from or pumped into the well. Accurate monitoring of the well is required for the following reasons:

- To compensate for the volume of pipe introduced into the hole
  - If the surface pressures are close to maximum allowable prior to the stripping operation
  - If the pipe has to be stripped out of the hole. In this case, there will be a tendency for the volume of metal removed from the well to be replaced by influx fluid.

In these circumstances it may be necessary to implement the dynamic stripping technique.

- To compensate for influx migration
- Influx migration is indicated by a gradual increase in fluid bled from the well even though the correct surface pressure is maintained.
- To allow an increase in surface pressure as the BHA and drillpipe enters the influx

When the BHA/drillpipe is run into the influx, the height of the influx will be considerably increased. This can cause a significant decrease in hydrostatic pressure in the annulus, requiring a greater surface pressure to maintain a constant bottomhole pressure. A potential problem arises if this condition is undetected.

It is recommended that the potential increase in surface pressure resulting from entering the influx should be estimated before stripping into the hole; this is then added to the initial calculated choke pressure at the start of the strip.

9.5 Annular Stripping

There are two stripping techniques, Annular and Ram combination stripping.

Annular stripping is considered to be the most satisfactory technique. It involves less risk than ram combination stripping for the following reasons:

- Annular stripping is a relatively simple technique.
- During annular stripping the only item of well control equipment that is subject to high levels of stress is the annular element
• The control system is not highly stressed during the operation (as is the case during ram combination stripping)

• The annular element can be changed out on a surface stack when pipe is in the hole by inserting a split element

If surface pressures indicate that annular stripping is not possible, attempts should be made to reduce the pressures in order to enable annular stripping to be used. The most appropriate technique will depend on the position of the influx in the hole. The options are; to circulate out the influx, to lubricate the influx from the well or to bullhead.

To ensure that the annular is not subjected to excessive pressures as the tool joint is stripped through the element, a surge dampener must be placed in the closing line. This may not be necessary on a surface stack if the pressure regulator can respond fast enough to maintain a constant closing pressure as a tool joint is stripped through the annular.

As a word of caution, some drilling contractors have installed check valves in the control lines to the BOPs; the purpose being to ensure that the BOP stays closed if the hydraulic supply is lost. However, if a check valve is installed in the closing line to an annular BOP, it will not be possible to reduce the closing pressure once the annular has been closed.

In order to reduce the annular closing pressure, in this case, it will be necessary to open the annular having closed another ram to secure the well.

9.6 Annular Volumetric Stripping Procedure

Having shut in the well, the following procedure can be used as a guideline for the implementation of annular volumetric stripping. It is assumed that the well was shut in by stabbing a full opening drillpipe safety valve or top drive (Kelly) had been installed therefore enabling the closing of the drillstring with a full opening drillpipe safety valve.

Shut-in pressures and volumes should be recorded to establish where the influx is and best estimate to the type of influx. A full work stripping sheet can then be completed.

• Install drillpipe dart.

  Allow the dart to fall until it seats in the dart sub. To check that the dart is functioning properly, bleed off pressure at the drillpipe (restrict volumes bled off to an absolute minimum, typically 1/2 to 1 bbl).

  If the dart does not hold pressure, allow more time for the dart to drop or consider circulating the dart into place (restrict volumes pumped to a minimum).
If the dart still does not hold pressure or there is no dart sub in the string, install a Gray valve above the fully opening drillpipe safety valve.

- Monitor surface pressures.
  Surface pressures should be monitored after the well has been shut in to check for influx migration. If the influx is migrating, it may be necessary to implement volumetric control whilst preparing to strip.

If the pipe is off bottom, it will not be possible to identify the type of influx in the usual manner. However, a high surface pressure caused by a relatively small underbalance usually indicates that the influx contains a significant quantity of gas.

- Determine the capacity and displacement of the drillpipe.
  It will be necessary to bleed mud from the well to compensate for the volume of pipe introduced into the hole.

This volume is equal to the sum of the capacity and the displacement of the pipe. There are various tables which outline these quantities, but a reasonable estimation can be made as follows:

Displacement and capacity = OD^2 \times 0.000971 \text{ (bbl/ft)}

where OD = outer diameter of the pipe (in)

Allowance should also be made for the extra volume of metal in the tool joints.

- Perform necessary calculations, as below, and complete stripping worksheet.
  Calculate hydrostatic pressure per barrel of mud.

Should migration occur, it will be necessary to increase choke pressure to allow for influx migration. The hydrostatic pressure equivalent of the mud in the hole is calculated as follows:

\[
\text{Hydrostatic pressure equivalent} = \frac{445.7 \times MW}{(d_{hc}^2 - d_o^2)} \text{ (psi/bbl)}
\]

Where:

MW = mud weight in the hole (SG)

dhc = hole/casing ID (in)
do = drillstring OD (in)

or if the pipe is above the influx:

\[
\text{Hydrostatic pressure equivalent} = \frac{445.7 \times MW}{d_{hc}^2} \text{ (psi/bbl)}
\]
Calculate a choke working pressure margin for a set volume increase as this will be added to initial shut-in choke pressure.

Estimate increase in surface pressure due to BHA entering the influx.

It is possible to estimate the maximum possible pressure increase due to the BHA entering the influx as follows:

Max possible surface

Pressure increase (psi) = 445.7 \times (MW - Gi) \times V \times \left( \frac{1}{(d_{hc}^2 - d_{oi}^2)} - \frac{1}{d_{hc}^2} \right)

Where:

MW = mud weight in the hole (SG)

Gi = influx gradient, converted to SG (water = 1SG)

V = volume of influx (bbl)

dhc = hole/casing ID (in)

do = BHA OD (in)

This pressure should be added to initial choke pressure together with a choke handling margin (typically 50 to 100 psi) when starting to strip.

**Note:** Care should be taken with this calculation as many BHAs have minimum drillcollars in use and rely on heavy weight drillpipe. If this is the case, the correct calculation should be used.

- Line up choke manifold so that returns are taken to the trip tank allowing accurate measurements to be recorded. Preference is to have a calibrated stripping tank take off from the trip tank. If this is not installed, the worksheet will reflect any net gain over calculated/predetermined closed end pipe displacement.

  Ensure that all surface lines are flushed through and full prior to stripping commencing.

- Hold pre stripping meeting and ensure that clear responsibilities have been assigned and everyone understands his role.

- Reduce annular closing pressure.

  The BOP manufacturers recommend that the closing pressure is reduced, prior to stripping, until a slight leakage occurs through the BOP. This reduces the wear on the annular by lubricating the element during stripping.
• Strip in the hole.
   The pipe should be slowly lowered through the annular whilst the surface pressure is maintained at the calculated pressure by choke manipulation whilst running the pipe in the hole.

   **Note:** Good communications is required between driller and choke operator. The running speed should be reduced when a tool joint passes through the annular. The optimum speed would be established from stripping drills. The pipe should be filled with mud at suitable intervals, typically every stand but at a maximum every 5 stands. Use original mud weight.

• Monitor surface pressures and volumes.
   Surface pressures, volumes and all relevant data should be recorded on the Stripping Worksheet. Additional volume over calculated displacement will indicate that the influx is migrating. Choke pressure should be allowed to increase by the working pressure margin for each set increase in volume.

• Strip to bottom. Kill the well.
   The only sure method of killing the well will be to return the string to bottom and implement standard well kill techniques.
Abu Dhabi Company For Onshore Oil Operations

Volumetric Stripping Worksheet

<table>
<thead>
<tr>
<th>Well No.</th>
<th>Rig:</th>
<th>Date:</th>
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</table>

| Hole Depth = .......... ft | HOLE DIA = .......... bbl/ft = .......... psi/bbl |
| Bit Depth = .......... ft | DC OD in = .......... bbl/ft = .......... psi/bbl |
| Csg Shoe = .......... ft | DP OD in = .......... bbl/ft = .......... psi/bbl |
| DC Length = .......... ft | DC/OH Volume= ....... bbl | Ave Std Length = ....... ft |
| SIDPP = .......... psi | Influx size = ....... bbl | Mud Gradient = ....... sg |
| SICP = .......... psi | Influx Gradient = ....... sg | C/E DP Displ.= ....... bbl/ft |
| Pipe in inf = .......... psi | Dp in inf = ....... psi | C/E DP Displ. = ....... bbl/std |

Notes

---------------------------------------------------------------------------------
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Initial choke pressure to be = SICP + Choke handling s/f + Pipe entering influx + working pressure margin

<table>
<thead>
<tr>
<th>Time</th>
<th>Pipe Stripped ft</th>
<th>Bit Depth ft</th>
<th>Choke psi</th>
<th>Trip Tank Vol Bbl</th>
<th>Trip Tank Inc Bbl (A)</th>
<th>Pipe Disp. Bbl (B)</th>
<th>Net Gain Bbl (A-B)</th>
<th>Accum. Net Gain bbl</th>
<th>Remarks</th>
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9.7 Ram Combination Stripping

There are two types of ram combination stripping; annular to ram, and ram to ram. Both techniques must be considered if either the tool joint cannot be lowered through the annular or the surface pressure is greater than the rated pressure of the annular and this pressure cannot be reduced to within safe limits.

Annular to ram stripping is preferable to Ram to Ram, unless surface pressures indicate that the annular cannot operate reliably.

For both ram combination techniques there is a requirement that:

- There is sufficient space for the tool joint between the two stripping BOPs.
- There is an inlet at the stack between the two BOPs used for stripping.
- There is a suitable level of redundancy in the stack to ensure the lowest BOP is not used during the stripping operation.

API RP 53 (issued 1984) states, ‘The lowermost ram should not be employed in the stripping operation. This ram should be reserved as a means of shutting in the well if other stack components of the blowout preventer fail. It should not be subjected to the wear and stress of the stripping operation’.

In a critical situation, it may be possible to modify a surface stack to suit these conditions after a kick has been taken.

The risks involved in ram combination stripping can be assessed by considering the following points:

- The high level of drillcrew co-ordination required.
- The level of stress placed on the BOP elements.
- The level of stress placed on the BOP control system.
- The possibility of replacing the worn BOP elements during operation.

9.8 Ram Combination Stripping Procedure

Usually one or more of the requirements above is not respected (space for tool joint between rams, inlet at the BOP between rams or usage of lower rams for stripping); for any one of these reasons and in order to use this well control method:

- Set string on lower pipe rams (with closed FOSV or Gray valve on).
- Lay down kelly.
• Re-arrange BOP stuck as shown on figures (3-3, 3-4, 3-5 and 3-6) to have from top to bottom:
  o Annular preventer
  o Blind/shear rams
  o Drilling spool with side inlet.
  o Upper pipe rams
  o Kill and chock lines
  o Lower pipe rams
• Screw back onto string and pull back FOSV to surface
• Open FOSV.
• Proceed to killing procedure below.

The following procedure can be used as a guideline for the implementation of annular to ram stripping. The procedure for ram to ram stripping will be similar.

• Monitor surface pressures.
• Determine the capacity and displacement of the drillpipe.
• Calculate hydrostatic pressure per barrel of the mud.
• Estimate the increase in surface pressure due to the BHA entering the influx.
• Check ram space-out to confirm the distance BRT of the two preventers that will be used for stripping.
• Allow the surface pressure to increase by the overbalance margin.
• Reduce annular closing pressure and strip in.
• Stop when tool joint is above annular (refer to Figure 3-3).
• Close pipe ram at normal regulated manifold pressure.
• Bleed ram cavity pressure.

Before the annular is opened it will be necessary to bleed down the pressure below it (refer to Figure 3-4).

• Reduce ram operating pressure.
• Open annular. Lower pipe.
• Stop when tool joint is just below annular (refer to Figure 3-5)
• Close annular at maximum operating pressure.
• Pressurize ram cavity to equalize across ram (refer to Figure 3-6)
• Do not use wellbore pressure to equalize across the ram.
• Reduce annular closing pressure.
• Open pipe ram.
• Continue to strip in according to the above procedure. Kill the well.
9.8.1 Annular to Ram Stripping

Step 1

- Ram opened
- Annular closed
- Stop Stripping-in when tool joint is above the annular

![Diagram of Annular to Ram Stripping - Step 1](image_url)

*Figure 3-3: Annular to Ram Stripping – Step 1*
9.8.2 Annular to Ram Stripping

Step 2

- Ram closed
- Pressure between Ram and annular bled-off
- Annular opened

Figure 3-4: Annular to Ram Stripping – Step 2
9.8.3 Annular to Ram Stripping

Step 3

- Strip in until tool joint is just below annular

Figure 3-5: Annular to Ram Stripping – Step 3
9.8.4 Annular to Ram Stripping

Step 4

- Annular closed
- Pressure between annular and ram equalized
- Continue as step 1

Figure 3-6: Annular to Ram Stripping – Step 4
9.9 Dynamic Stripping Procedure

The purpose of this technique is to maintain constant choke pressure as the pipe is stripped into the hole. This is achieved by circulating at a constant rate across the end of the chokeline. A manual choke should be used and the equipment rigged up as shown in Figure 3-7.

For this technique to be effective, the pump output must be considerably greater than the rate at which the volume of pipe is introduced into the well. If the pump rate is too low, pressure surges will be caused at the choke as the pipe is stripped in, and the choke pressure will fluctuate. The same is true for stripping out of the hole, in which case the choke pressure may drop as pipe is stripped from the well, if the pump rate is too low. This may cause further influx to occur. 4bbls/min is the recommended pump rate.

The main problem associated with this technique is that migration and entrance into the gas bubble may not easily be detected at surface. If no
allowance is made for these complications, further influx may be allowed to occur. To avoid this, the mud tank levels should be closely monitored to ensure that the levels rise, or drop, in direct relation to the volume of pipe that has been stripped into, or out of, the well. If any discrepancy is noticed, the well should be shut in and the surface pressures verified. Influx migration should be dealt with using the Volumetric Method.

The Dynamic Stripping technique can be used during either annular or ram combination stripping. For annular stripping it is implemented along the following lines:

- Install drillpipe dart (or Gray valve if no dart sub).
- Monitor surface pressures.
- Determine the capacity and displacement of the drillpipe.
- Calculate hydrostatic pressure per barrel of the mud.
- Estimate the increase in surface pressure due to the BHA entering the influx.
- Allow the surface pressure to increase by the overbalance margin.
- Line up the pump to the chokeline.
- Ensure that the manual choke is fully closed. Open chokeline valve(s).
- Open the manual choke at the same time as the pump is brought up to speed.
- Maintain final shut-in pressure on the choke.
- Reduce annular closing pressure.
- Strip in the hole.
- Monitor surface pressures and pit level.

If the choke pressure increases significantly as the pipe is stripped into the hole, either reduce the pipe running speed or increase the circulation rate.

Use the Stripping Worksheet to record all the relevant data. It is very important to accurately record pressures and mud volumes whilst stripping.

- Strip to bottom. Kill the well. Fill the pipe as required.
WELL CONTROL EQUIPMENT

Any BOP equipment arrangement or pressure rating variation from the standard set forth herein must be approved by the Drilling Manager. The Drilling Supervisor shall ensure that the proper equipment is available and correctly installed. All BOP equipment shall comply with API specifications.

The BOP equipment must be arranged to allow:

- A means of closing the top of the open hole, as well as around drill pipe or collars, and stripping the drill string to bottom.
- A means of pumping into a hole and circulating out a well kick.
- A controlled release of the influx.
- A redundancy in equipment in the event that any one function fails.

1. BOP Stack requirements

1.1 Class I (10,000 psi) BOP Stack

Where the surface pressure is anticipated to be between 5001 psi to 10000 psi the well control equipment and BOP Stack (Figure 3-8) will consist of:

- One annular preventer (5,000 psi).
- Three singles or one double and one single hydraulic operated ram type preventers. (10,000 psi – 35% H₂S Elastomer)
  - Two must be equipped with a pipe ram (either fixed or variable) one must be fixed.
  - One must be equipped with blind/shear ram
- One full opening drilling spool with two each 4 1/16” side outlets.
- One choke line with two full bore valves (each have 4-1/16” flange), of which one is hydraulically operated remotely, connected to the choke manifold.
- One choke line with two full bore valves, of which one is hydraulically operated remotely, for emergency use only below bottom rams.
- One kill line with two full bore valves and a non return valve (NRV), connected to the kill manifold and the cement unit, or other pumping unit.
• One kill line with two full bore valves connected to the cement unit or other pumping unit below bottom rams.

• The outlet on the individual ram BOP should not be used for the primary kill and choke lines unless it is not possible to install the drilling spool.
Figure 3-8: Class (I) -10,000 psi BOP Stack and Choke Manifold
1.2 Class II (5,000 psi) BOP Stack

Where the surface pressure is anticipated to be less than 5,000 psi and high percentage of H₂S is expected (between 5% and 35%) the well control equipment and BOP Stack (see Figure 3-9) will consist of:

- One annular preventer (5000 psi)
- Three singles or one double and one single hydraulic operated ram type preventers. (5000 psi – 35% H₂S Elastomer)
  - Two must be equipped with a pipe ram (either fixed or variable) one must be fixed.
  - One must be equipped with blind/shear ram.
- One full opening drilling spool with two each 3 1/8” side outlets.
- Two Separate kill and choke lines (each have 3 1/8” flange) shall be provided with two full bore valves of which one valve of each line is hydraulically operated connected to the kill and pumping manifolds. The kill line must be fitted with non return valve (NRV).
- One kill line with two full bore valves connected to the cement unit or other pumping unit.

When the BOP stack consists of a double ram type preventer with proper size side outlets the kill and choke lines may be connected to the outlets of the lower preventer. In this case the drilling spool may be omitted.
Class (II) BOP Stack

Figure 3-9: Class (II) -5,000 psi BOP stack and choke manifold
1.3 Class III (5,000 psi) BOP Stack

Where the surface pressure is anticipated to be less than 5,000 psi and high H₂S is expected (between 5% and 35%) the well control equipment and BOP Stack (see Figure 3-10) will consist of:

- One annular preventer (5,000 psi)
- One double or two single hydraulic operated ram type preventers (5,000 psi – 35% H₂S Elastomer).
  - One must be equipped a pipe ram (either fixed or variable).
  - One must be equipped with blind/shear ram
- One full opening drilling spool with two each 3 1/8" side outlets.
- Two dual purpose kill and choke lines with two full bore valves (each have 3 1/8" flange) of which one valve of each line is hydraulically operated connected to the kill and pumping manifolds. The kill line must be fitted with non return valve (NRV).
- If the dual purpose kill and choke lines are not provided, separate kill and choke lines shall be provided.

When the BOP stack consists of a double ram type preventer with proper size side outlets the kill and choke lines may be connected to the outlets of the lower preventer. In this case the drilling spool may be omitted.
Class (III) BOP Stack

Figure 3-10: Class (III) -5,000 psi BOP stack and choke manifold
1.4 Class IV (5,000 psi) BOP Stack

Where the surface pressure is anticipated to be less than 5,000 psi and low/no H₂S (less than 5%) is expected the well control equipment and BOP Stack (see Figure 3-10) will consist of:

- One annular preventer (5,000 psi)
- One double or two single hydraulic operated ram type preventers (5,000 psi – 5% H₂S Elastomer)
  - One must be equipped a pipe ram (either fixed or variable).
  - One must be equipped with blind/shear ram
- One full opening drilling spool with two each 3 1/8” side outlets.
- Two dual purpose kill and choke lines with two full bore valves (each have 3 1/8” flange) of which one valve of each line is hydraulically operated connected to the kill and pumping manifolds. The kill line must be fitted with non return valve (NRV).
- If the dual purpose kill and choke lines are not provided, separate kill and choke lines shall be provided.

When the BOP stack consists of a double ram type preventer with proper size side outlets the kill and choke lines may be connected to the outlets of the lower preventer. In this case the drilling spool may be omitted.
Figure 3-10: Class (IV) -5,000 psi BOP stack and choke manifold
1.5 Accumulator Closing Units

1.5.1 Fluid Requirements

The accumulator shall store enough fluid under pressure to close all preventers, open the choke hydraulic control gate valve (HCR), and retain 50% of the calculated closing volume with a minimum of 200 psi above pre-charge pressure, without assistance of the accumulator pumps.

1.5.2 Design requirements

The accumulator and all fittings are to be 3000 psi working pressure. Hydraulic lines from the accumulator to the BOP stack shall be designed and manufactured in compliance with API specifications.

1.5.3 Bottle Pre-Charge Requirements

The accumulator bottles will be pre-charged with Nitrogen as per manufacture’s specifications. The minimum required pre-charge pressure for a 3000 psi working pressure accumulator is 1000 psi. The nitrogen pressure should be checked and adjusted prior to connecting the closing unit to the BOP stack.

The accumulator should be capable of closing each ram within 30 seconds. Closing time should not exceed 20 seconds for annulars smaller than 18 ¾” nominal bore and 45 seconds for annular preventers of 18 ¾” and larger.

1.5.4 Operating control requirements

All accumulator controls must be in open or close position (not in neutral position).

1.5.5 Pump System

The primary electric/hydraulic pumps and secondary air/hydraulic pumps must be independent of each other and fully operational when the accumulator is in use. The low pressure for both systems (electric and hydraulic) is 2800 psi and the high pressure is 3000 psi.

1.6 Coiled Tubing Pressure Control Equipment Requirements

1.6.1 Equipment Requirements for wells with WHP (0-5,000 psi)

The following minimum equipment configuration is required for standard operations:
• Injector head 10,000 psi.
• Tandem side-door stripper assembly (10,000 psi).
• Quad BOP (10,000 psi).
  o Blind rams
  o Shear rams
  o Slip rams
  o Pipe rams
• Kill line inlet with double valves.

**Note:**
Each equipment item must have a working pressure of at least 10,000 psi.

1.6.2 **Equipment Requirements for wells with WHP (5,000-10,000 psi)**

The following minimum equipment configuration is required for high integrity rig up operations:

• Injector head 10,000 psi.
• Tandem side-door stripper assembly (10,000 psi).
• Quad BOP (10,000 psi).
  o Blind rams
  o Shear rams
  o Slip rams
  o Pipe rams
• Combi BOP’s (10,000 psi).

**Notes:**
• Each equipment item must have a working pressure of at least 10,000 psi.
• A kill line must be rigged up on high integrity rig up operations.
• Connections below the BOP must be flanged.
SECTION 7

TESTING OF BLOWOUT PREVENTION SYSTEM

1. General

1.1 Maintenance of Blowout Prevention Equipment

Blowout prevention equipment is emergency equipment and must be maintained in its proper working condition at all times. The Drilling Supervisor must insure that ADCO is provided with equipment that performs to our specifications by being an active participant in the maintenance requirements of the BOP equipment.

Several maintenance items which the Drilling Supervisor should verify on a daily basis (by reviewing the Driller’s pre-tour checklist or by personal observation) are listed below:

- Examine the fluid level in the accumulator. Make sure it is at the proper level and proper pressures are indicated on the accumulator, manifold, and annular pressure.
- Confirm the preventer controls are either in their proper opened or closed position (not neutral) and that leaks are not evident.
- Assure the preventer stack is well centered with the well so that vibrations are minimized while drilling.
- All preventers must be operated at least each time a trip is made. Alternate trip closures between the remote stations and the accumulator. The annular preventer does not have to be operated to complete shut-off. DO NOT close the pipe rams on open hole.
- The emergency kill line and choke/kill lines must be washed out as required to prevent mud solids settling. Clear water should be used to flush and fill the lines.
- DO NOT circulate green cement through the preventer stack or choke manifold. Always thoroughly flush with water any piece of blowout prevention equipment, which has come in contact with green cement and verify the equipment is clear upon the next nipple-up.
- Make sure the rig is centered over the well to reduce drill string and BOP equipment contact and abrasion.
- DO NOT use the kill line as a fill-up line during trips.
- If possible, install the ram preventers so that the ram doors are positioned above and shield the valves installed on the casing head below.
• All rigs shall maintain a logbook of BOP schematics detailing the components installed in each ram cavity. The logbooks shall contain the part number, description and installation date of ram blocks, top seals, ram or annular packers and bonnet/door seals. To be witnessed/co-signed by the Rig Manager and ADCO Drilling Supervisor.

• Only OEM parts are acceptable when repairing or redressing the BOPE. Furthermore, only an approved OEM high-temperature lubricant is acceptable for valve maintenance.

• At least one spare set of ram seals (top seals and packer rams) for all rams including packer rams for each size tubing or drill pipe, as well as bonnet seals, must be on the rig site.

• Ram blocks must not be dressed until ready to use.

• All BOP rubber goods must be kept in a cool place and remain in the original packaging with expiration dates.

• Preventer assemblies must be dismantled during yearly Major Rig Maintenance to inspect for internal corrosion and erosion and to check flange bolts.

• Manufacturer’s installation, operation, and maintenance (IOM) manuals should be available on the rig for all BOP equipment installed on the rig.

• New ring gaskets must be installed on each nipple-up at each connection, which has been parted. Ring gaskets should never be reused due to the limited amount of deformation, which a groove can make on a ring as it is compressed during installation.

• Studs and nuts must be checked for proper size and grade. Using the appropriate lubricant, torque should be applied in a criss-cross manner to the flange studs. All bolts should then be re-checked for the proper torque as prescribed in API Specification 6A.

• Field welding must not be performed on any BOP equipment. All major repairs to BOP equipment must be performed at an OEM (or OEM certified) facility.

• A full OEM Certification of the BOP and all related equipment (i.e. closing unit, choke manifold etc.) must be required at contract start-up and contract renewal with a maximum period of 3 years between re-certification.

• The BOP rams doors should be opened, cleaned, and visually inspected between wells, including servicing the manual tie-down screws.

• All elastomers exposed to well fluids should be changed at a maximum of every 12 months, unless visual inspection requires changing earlier.
• All BOP stacks and accumulators must have documentation of last inspection and certification.

1.2 General Pressure Testing Requirements

All BOP equipment pressure tests must be conducted in accordance with the following guidelines:

• Rig crews must be alerted when pressure test operations are underway. Only necessary personnel shall remain in the test area.

• All tests must be performed using clear water.

• The low-pressure test of each piece of BOP equipment shall be conducted at a pressure of 300 psi.

• The high-pressure testes will be based on BOP class. Refer to BOP Classification.

• The low-pressure test shall be performed first. DO NOT test to the high pressure and then bleed down to the low pressure. The higher pressure could initiate a seal after the pressure is lowered and thereby misrepresent the low pressure test.

• The initial high pressure test of the following equipment must be conducted up on installation at the rated working pressure of the weakest component:
  ○ Wellhead
  ○ Ram Type Preventers
  ○ Kill Line and Valves
  ○ Emergency Kill Line And Valves
  ○ Choke Line and Valves
  ○ Choke Manifold

• Subsequent high pressure tests of the above equipment must be conducted to a pressure greater than the maximum anticipated surface shut in pressure.

• The high pressure test (initial and subsequent) of the annular preventer must be conducted at 70% of the rated working pressure.

• The initial pressure test on the manifold and BOP hydraulic lines shall be at the rated working pressure of the closing unit (3000 psi). Subsequent pressure must be performed on each well installation at the same pressure or after repairs to the hydraulic circuit.
• BOP equipment (including blind rams and shear blind rams) shall be pressure tested (from below) as follows:
  o When installed
  o Before drilling out each string of casing
  o Following the disconnection or repair of any wellbore pressure seal in the wellhead/BOP stack (limited to the affected components only)
  o After a maximum of 14 days from the last pressure test.

• All valves located downstream of the valve being tested must be placed in the OPEN position.

• OPEN casing valves to the atmosphere when using the test plug to test the BOP stack to prevent possible leaks from rupturing the casing.

• OPEN annular valves when testing to prevent pack-off leaks from pressuring up outer casing strings.

• Vent the cup tester through the drillpipe when testing the upper 60 feet of casing to prevent possible leaks from rupturing the casing or applying pressure to the open hole.

• Casing rams must be tested to the ‘maximum anticipated surface pressure’, with a joint of casing connected to a test plug with appropriate cross-over.

• Variable Bore Rams (VBR) shall be tested with all sizes of pipe in use, excluding drill collars and bottom-hole tools.

• DO NOT close annular preventers on open hole for pressure tests. Annular should be shut on open hole in an emergency only.

• All-pressure tests must be held for a minimum duration of 5 minutes with no observable pressure decline.

• Only authorized personnel shall go in the test area to inspect for leaks when the equipment is under pressure.

• Tightening or repair work must be done only after pressure has been released and all parties have agreed that there is no possibility of trapped pressure.

• A pressure test is required after the installation of casing rams or tubing rams. This test is limited to the components affected by the disconnection of the pressure containment seal. The bonnet seals and rams shall be tested using a test joint connected to a test plug, or cup tester, with appropriate crossover.

• The initial pressure test performed on hydraulic chambers of annular preventers should be at least 1500 psi or as per manufacturer’s
recommendations. Initial pressure tests on hydraulic chambers of rams and hydraulically operated valves should be to the maximum operating pressure recommended by the manufacturer. Test must be run on both the opening and closing chambers. Subsequent pressure tests on hydraulic chambers should be upon re-installation.

- All pressure tests must be conducted with a test pump. Avoid the use of rig pumps for pressure testing. Cement units are acceptable.

- All test results must be documented on a pressure chart, with the following information,
  - Date of Test
  - Well Name
  - Rig Manager
  - ADCO Drilling Supervisor

2. Pressure Testing Procedure

The recommended pressure testing procedure for a Class 'II' 5,000 psi BOP hook-up is given in (Figure 3-11). This test procedure can be easily amended and made applicable for the other classes of preventer stacks. Although the actual testing sequence may vary somewhat, the ultimate objective must be achieved: To test each individual preventer, valve, and all associated lines in the BOP system from the wellbore direction at a (200 – 300) psi low-pressure and then a specified high-pressure.

The pressure source is shown down the drillpipe and through a perforated sub or ported test plug (excluding blind ram "or casing test), although a BOP side .outlet may be used. The annular and pipe rams are tested individually in this manner. The blind rams are tested after removing the drillpipe and applying pressure through the kill line, between closed rams and test plug.

In order to test each individual valve on the kill line, choke line, and manifold; proceed after pressure testing the far outside valves, (all other valves open) by opening these valves and closing each inside adjacent valve, pressure testing, and working inward to the stack.

Note:
The steps in the following procedure should be performed in numerical sequence. The instructions assume that at the beginning of each step, the equipment is arranged as in the end of the previous step. Therefore, if this particular procedure is not followed in sequence, erroneous test results may be obtained.

2.1 Function Testing and Flow Testing

Before applying test pressure to the preventers, perform the following:
• Close and open all preventers. DO NOT CLOSE pipe rams or annular preventer on open hole.

• Pump through the kill line, flow line, mud-gas separator, and choke lines with water to make sure none are plugged.
Figure 3-11: Class II-5,000 psi BOP stack and choke manifold
2.2 Fill the Stack with Water

Drain the mud from the BOP stack and fill with clear water.

2.3 Initial Test (prior to spud or upon installation)

<table>
<thead>
<tr>
<th>Component to be Tested</th>
<th>Recommended Pressure Test Low Pressure*, psi</th>
<th>Recommended Pressure Test High Pressure**, psi</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Rotating Head</td>
<td>200-300</td>
<td>Optional</td>
</tr>
<tr>
<td>2. Diverter Element</td>
<td>Minimum of 200.</td>
<td>Optional</td>
</tr>
<tr>
<td>3. Annular Preventer</td>
<td>200-300</td>
<td>Minimum of 70% of annular BOP working pressure.</td>
</tr>
<tr>
<td>• Operating Chambers</td>
<td>N/A</td>
<td>Minimum of 1500.</td>
</tr>
<tr>
<td>4. Ram Preventers</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Fixed Pipe</td>
<td>200-300</td>
<td>Working pressure of ram BOPs.</td>
</tr>
<tr>
<td>• Variable Bore</td>
<td>200-300</td>
<td>Working pressure of ram BOPs.</td>
</tr>
<tr>
<td>• Blind/Blind Shear</td>
<td>200-300</td>
<td>Working pressure of ram BOPs.</td>
</tr>
<tr>
<td>• Operating Chamber</td>
<td>N/A</td>
<td>Maximum operating pressure recommended by ram BOP manufacturer.</td>
</tr>
<tr>
<td>5. Diverter Flowlines</td>
<td>Flow Test</td>
<td>N/A</td>
</tr>
<tr>
<td>8. Choke Manifold</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Upstream of Last High</td>
<td>200-300</td>
<td>Working pressure of ram BOPs.</td>
</tr>
<tr>
<td>Pressure Valve</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Downstream of Last High</td>
<td>200-300</td>
<td>Optional</td>
</tr>
<tr>
<td>Pressure Valve</td>
<td></td>
<td></td>
</tr>
<tr>
<td>9. BOP Control System</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Manifold and BOP Lines</td>
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<td>Minimum of 3000.</td>
</tr>
<tr>
<td>• Accumulator Pressure</td>
<td>Verify Pre-charge</td>
<td>N/A</td>
</tr>
<tr>
<td>• Close Time</td>
<td>Function Test</td>
<td>N/A</td>
</tr>
<tr>
<td>• Pump Capability</td>
<td>Function Test</td>
<td>N/A</td>
</tr>
<tr>
<td>• Control Stations</td>
<td>Function Test</td>
<td>N/A</td>
</tr>
<tr>
<td>10. Safety Valves</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Kelly, Kelly Valves, and</td>
<td>200-300</td>
<td>Working pressure of component.</td>
</tr>
<tr>
<td>Floor Safety Valves</td>
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<td></td>
</tr>
<tr>
<td>11. Auxiliary Equipment</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Mud/Gas Separator</td>
<td>Flow Test</td>
<td>N/A</td>
</tr>
<tr>
<td>• Trip Tank, Flo-Show, etc.</td>
<td>Flow Test</td>
<td>N/A</td>
</tr>
</tbody>
</table>

* The low pressure test should be stable for at least 5 minutes.

** The high pressure test should be stable for at least 5 minutes. Flow-type tests should be of sufficient duration to observe for significant leaks.

** The rig available well control equipment may have a higher rated working pressure than site required. The site specific test requirement should be considered for these situations.
### 2.4 Subsequent Tests (not to exceed 14 days)

<table>
<thead>
<tr>
<th>Component to be Tested</th>
<th>Recommended Pressure Test- Low Pressure*, psi</th>
<th>Recommended Pressure Test- High Pressure**, psi</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Annular Preventer</td>
<td>200-300</td>
<td>Minimum of 70% of annular BOP working pressure.</td>
</tr>
<tr>
<td>2. Ram Preventers</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• All Rams</td>
<td>200-300</td>
<td>Greater than the maximum anticipated surface shut-in pressure.</td>
</tr>
<tr>
<td>3. Choke, Line &amp; Valves</td>
<td>200-300</td>
<td>Greater than the maximum anticipated surface shut-in pressure.</td>
</tr>
<tr>
<td>5. Choke Manifold</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Upstream of Last High Pressure Valve</td>
<td>200-300</td>
<td>Greater than the maximum anticipated surface shut-in pressure.</td>
</tr>
<tr>
<td>• Downstream of Last High Pressure Valve</td>
<td>Optional</td>
<td>Optional</td>
</tr>
<tr>
<td>6. BOP Control System</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Manifold and BOP Lines</td>
<td>N/A</td>
<td>Optional</td>
</tr>
<tr>
<td>• Accumulator Pressure</td>
<td>Verify Pre-charge</td>
<td>N/A</td>
</tr>
<tr>
<td>• Close Time</td>
<td>Function Test</td>
<td>N/A</td>
</tr>
<tr>
<td>• Pump Capability</td>
<td>Function Test</td>
<td>N/A</td>
</tr>
<tr>
<td>• Control Stations</td>
<td>Function Test</td>
<td>N/A</td>
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<tr>
<td>7. Safety Valves</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Kelly, Kelly Valves, and Floor Safety Valves</td>
<td>200-300</td>
<td>Greater than the maximum anticipated surface shut-in pressure</td>
</tr>
<tr>
<td>8. Auxiliary Equipment</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Mud/Gas Separator</td>
<td>Optional Flow Test</td>
<td>N/A</td>
</tr>
<tr>
<td>• Trip Tank</td>
<td>Flow Test</td>
<td>N/A</td>
</tr>
</tbody>
</table>

* The low pressure test should be stable for at least 5 minutes.

** The high pressure test should be stable for at least 5 minutes. Flow-type tests should be of sufficient duration to observe for significant leaks.
2.5 Casing Test

A casing test is generally conducted at nipple-up when testing DV or float equipment. In addition, this test is required every 14 days (along with the scheduled BOP test), with the use of a cup tester, to provide a pressure test on casing head valves and verify casing integrity.

To conduct a casing test, perform the following:

- Connect the pressure source to the kill line and open kill line valves #1 and #2.

  **Note:** VERY IMPORTANT - Monitor valves #5, #6, #7 and #8 for leaks/well flow.

- Open all valves and chokes on choke manifold. Close valve #4 on choke line.

- Close outer casing head valves #5 and #8.

- Close the blind/shear blind rams (or upper pipe rams, if pipe in the hole).

- Pump into the well through the kill line monitoring/recording the test pressure at the test pump. For all casing strings other than drive pipe or structural casing, conduct the test to 70% of the minimum internal yield (burst) of the casing.

- To test inner casing head valves, close valves #6 and #7 and open outer valves #5 and #8. See Figure (3-12).

  **Note:** No manufacturer recommends opening rams, which are holding pressure. Damage to the ram rubbers, ram blocks and ram cavities may occur.
2.6 Shear Blind Ram Test

To pressure test the Shear Blind Ram (or Blind Ram), the following is required:

- Land test plug in the casing head and remove running tool from the wellbore.
- Connect the pressure source to the kill line and open kill line valves #1 and #2 (see Figure 3-13).

**Note:** Monitor valves #5, #6, #7 and #8 for well flow.
• Open all valves and chokes on the choke manifold.
• Open all casing head valves and close the choke line valve #4.
• Close the shear blind rams.

Figure 3-13  Shear Blind Ram Test
2.7 Annular Preventer

Test the annular preventer as follows:

- Land the test plug and test joint (Figure 3-14) in the casing head.
- Connect the pressure source to the test joint at the rig floor.
- Close the kill line HCR (valve #1) and open all other kill line valves (the kill line check valve should be crippled).
- First, open all choke line and choke manifold valves. Then close the outermost choke manifold valves #15, #16, #17, and #18 (before buffer tank). See Figure (3-15).
- Verify that the casing head valves #6 and #7 are open.
- Close the annular preventer and pump into the well through the test joint. Conduct the low-pressure test first at a pressure of 300 psi. Conduct the high pressure test next at a pressure equal to 70% of the rated working pressure of the annular preventer.
Figure 3-14 Test Plug Assembly
Figure 3-15 Annular Test

2.8 Upper Pipe Rams

Without changing the choke manifold or testing arrangement, immediately test the upper pipe rams as follows.

- Close valve #9 (see Figure 3-16).
- Close the upper pipe rams and pump into the well through the test joint. Conduct the low-pressure test first at a pressure of 300 psi. Conduct the high pressure test next at the pressure specified in previous requirements. Confirm that choke manifold valve #9 is not leaking.

Note: Monitor valves #5, #6, #7 and #8 for well flow.
Figure 3-16 Upper Pipe Ram Test
2.9 Positive-Sealing Choke Test

If the chokes are designed to be positive sealing, test them as described below; otherwise, proceed to Step 2.8

- Open outermost choke manifold valves #15, #16, and #18.
- Close positive-sealing chokes (see Figure 3-17).
- Close the upper pipe rams and pomp into the well through the test joint. Conduct the low-pressure test first at a pressure of 300 psi. Conduct the high pressure test next at the pressure specified in previous requirements.

**Note:** Monitor valves #5, #6, #7 and #8 for well flow.
2.10 **Choke Manifold Valves (continued)**

Continue testing the choke manifold valves by performing the following:

- Open outermost choke manifold valves #15, #16, #17, and #18.
- Open chokes.
- Close choke manifold valves #10, #13 and #14 (see Figure 3-18).
- Close the upper pipe rams and pump into the well through the test joint. Conduct the low-pressure test first at a pressure of 300 psi. Conduct the high pressure test next at the pressure specified in previous requirements.

**Note:** Monitor valves #5, #6, #7 and #8 for well flow.

![Figure 3-18 Choke Manifold Valves (Continue)](image_url)
2.11 Choke Manifold Valves (continued)

Continue testing the choke manifold valves by performing the following:

- Open choke manifold valves #10, #13.
- Close choke manifold valves #11, #12 (see Figure 3-19).
- Close the upper pipe rams and pump into the well through the test joint. Conduct the low-pressure test first at a pressure of 300 psi. Conduct the high pressure test next at the pressure specified in previous requirements.

**Note:** Monitor valves #5, #6, #7 and #8 for well flow.

![Figure 3-19 Choke Manifold Valves (Continue)](image-url)
2.12 Choke Manifold Valves (continued)

- Open choke manifold valves, #11, #12, and #14.
- Close choke manifold valve #9 (see Figure 3-20).
- Close the upper pipe rams and pump into the well through the test joint. Conduct the low-pressure test first at a pressure of 300 psi. Conduct the high-pressure test next at the pressure specified in previous requirements.

**Note:** Monitor valves #5, #6, #7 and #8 for well flow.

![Choke Manifold Valves Diagram](image-url)
2.13 Choke Line HCR Valve

Test the choke line HCR valve by performing the following:

- Open choke manifold valve #9.
- Open choke line valve #3.
- Close outer choke line HCR (valve #4). (See Figure 3-21)
- Close the upper pipe rams and pump into the well through the test joint. Conduct the low-pressure test first at a pressure of 300 psi. Conduct the high pressure test next at the pressure specified in previous requirements.

Note: Monitor valves #5, #6, #7 and #8 for well flow.
2.14 Choke and Kill Line Manual Valves

Test the inner choke and kill line valves by performing the following:

- Open choke line HCR valve #4.
- Close choke line manual valve #3.
- Open kill line HCR valve #1.
- Close kill line manual valve #2 (see Figure 3-22).
- Close the upper pipe rams and pump into the well through the test, joint. Conduct the low-pressure test first at a pressure of 300 psi. Conduct the high pressure test next at the pressure specified in previous requirements.

Note: Monitor valves #5, #6, #7 and #8 for well flow.
No manufacturer recommends opening rams, which are holding pressure. Damage to the ram rubbers, ram blocks and ram cavities may occur.

Figure 3-22 Choke Line HCR Valve
2.15 Bottom Pipe Ram

Test the master pipe rams by performing the following:

- Open the upper pipe rams (see Figure 3-23).
- Close the master pipe rams and pump into the well through the test joint. Conduct the low-pressure test first at a pressure of 300 psi. Conduct the high pressure test next at the pressure specified in previous requirements.

Notes:
- Monitor valves #5, #6, #7 and #8 for well flow.
- No manufacturer recommends opening rams, which are holding pressure. Damage to the ram rubbers, ram blocks and ram cavities may occur.

Figure 3-23 Bottom Pipe Ram Test
2.16 Kelly, Surface Circulating Equipment, and Safety Valves

- Pick up Kelly and install full-opening safety valve on bottom of lower Kelly valve.
- Using an adaptor, connect to an independent test pump or cement pump.
- Open appropriate standpipe valves and all Kelly valves.
- Fill the system with water and close standpipe valve to test the standpipe, rotary hose, swivel, and Kelly.
- Conduct the low-pressure test first at a pressure of 300 psi.
- Conduct the high-pressure test next at the pressure specified in previous requirements.
- By alternating closing upstream and opening downstream valves, all the Kelly valves could be tested without pressuring up again, although it may not possible to operate the upper Kelly valve under pressure.
- The inside BOP (float type) can be tested similarly by installing below the full opening safety valve and opening all valves through the standpipe.

2.17 Casing Head Valves

Test all valves on the casing head individually to their rated working pressure on installation and 70% of casing burst on subsequent pressure tests with a cup tester at +/- 90°.

2.18 Accumulator Tests

These tests are for the purpose of determining the operating condition of the accumulator and BOP system. They shall be performed every 14 days, at the same time the BOP equipment is pressure tested, and at any other time deemed necessary by ADCO Drilling Supervisor. The results shall be noted on ADCO BOP Pressure Test Report. To analyze the performance of the accumulator, the results of each test should be compared with results of several previous tests. Any increase in closure or recharge time indicates an immediate need for a thorough examination of the accumulator system. The accumulator test shall include the following,

- Record the accumulator capacity and useable volume.
- Record the accumulator pressure.
- Record the pre-charge pressure and last date checked.
- Conduct low and high-pressure test on annular and all ram preventers.
• Record the closing and opening times for each component.

**Note:** Alternate accumulator bi-weekly tests between the main nitrogen unit (with charging system isolated) and air/electric back-up system (with bottle banks isolated).

Preventer functions should also be operated remotely to insure proper operation of all functions from the remote stations.

The accumulator test shall also comply ADCO general requirements as follows:

• Closing time for ram preventers should not exceed 20 seconds.
• Closing time for annular preventers (less than 18-3/4") should not exceed 30 seconds.
• Closing time for annular preventers (18-3/4" and larger) should not exceed 45 seconds.
• The accumulator must have enough stored fluid under pressure to close all preventers, open the choke hydraulic control gate valve (HCR), and retain 50% of the calculated closing volume with a minimum of 200 psi above pre-charge pressure, without assistance of the accumulator pumps.
• The accumulator-backup system shall be automatic, supplied by a power source independent from the power source to the primary accumulator-charging system, and possess sufficient capability to close all blowout components and hold them closed.
Abu Dhabi Company for Onshore Oil Operations  
Drilling Division  

**BOP TEST REPORT**

<table>
<thead>
<tr>
<th>Rig</th>
<th>Date of this Test</th>
<th>Depth (ft)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Well</td>
<td>Date of the Last Test</td>
<td>Shoe (MD/TVD) (ft)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>EQUIPMENT</th>
<th>Low Test Pressure</th>
<th>Duration (Mins)</th>
<th>High Test Pressure</th>
<th>Duration (Mins)</th>
<th>Remarks</th>
</tr>
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<tbody>
<tr>
<td>Annular Preventer</td>
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<td></td>
<td></td>
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<td></td>
</tr>
<tr>
<td>Top Pipe Rams</td>
<td></td>
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</tr>
<tr>
<td>Blind/Shear Rams</td>
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<td>Lower Pipe Rams</td>
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</tr>
<tr>
<td>Choke line HCR</td>
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<tr>
<td>Kill Line HCR</td>
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<tr>
<td>Lower Kelly coke</td>
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<tr>
<td>Upper Kelly Coke</td>
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<td>FOSF</td>
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<td>Choke Manifold</td>
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<td>Standpipe Manifold</td>
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<table>
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<tr>
<th>Reason for Test</th>
<th>Initial</th>
<th>Weekly</th>
<th>Ram Change</th>
<th>Other</th>
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Comments: ..........................................................................................................................

ADCO DS .................  Rig Manager ...............
### ACCUMULATOR TEST REPORT

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<thead>
<tr>
<th>Rig</th>
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<th>Date</th>
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<tbody>
<tr>
<td>Last Casing</td>
<td>Shoe (MD)</td>
<td>Shoe (TVD)</td>
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#### Pre-Test Checks

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<tr>
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<tr>
<td>Manifold Pressure</td>
<td>Checked</td>
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</tr>
<tr>
<td>Accumulator Reservoir</td>
<td>Level – OK?</td>
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<td>Accumulator Pumps</td>
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#### Capacity Test

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<th>Accumulator Pressure (psi)</th>
<th>Time (Seconds)</th>
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<td>Final</td>
</tr>
<tr>
<td>Close Annular Preventer</td>
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</tr>
<tr>
<td>Close Top Pipe Rams</td>
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<tr>
<td>Close Lower Pipe Rams</td>
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<tr>
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<tr>
<td>Open HCR</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Accumulator Pre-Charge</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Final Accumulator Pressure should be greater than the pre-charge pressure**

<table>
<thead>
<tr>
<th>Function</th>
<th>Activation Pressure (psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Accumulator low pressure</td>
<td></td>
</tr>
<tr>
<td>alarm working at all</td>
<td></td>
</tr>
<tr>
<td>stations?</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Function</th>
<th>Activation Pressure (psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Recharge Time (Electric /</td>
<td></td>
</tr>
<tr>
<td>Air / Both) pumps</td>
<td></td>
</tr>
<tr>
<td>Pump activation pressure</td>
<td></td>
</tr>
<tr>
<td>test (Electric / Air /</td>
<td></td>
</tr>
<tr>
<td>Both)</td>
<td></td>
</tr>
<tr>
<td>ON</td>
<td></td>
</tr>
<tr>
<td>OFF</td>
<td></td>
</tr>
</tbody>
</table>

**Comments:**

<table>
<thead>
<tr>
<th>Function</th>
<th>Activation Pressure (psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
</tr>
</tbody>
</table>

---

ADCO DS ..........................  Rig Manager ..........................

---

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DM :  
Date :  
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SECTION 8

WELL CONTROL DRILLS

1. Kick Drill While Drilling - Code No. D1

1.1 Frequency

This drill must be carried out intensively, as soon as the BOP stack is installed on each well until the reactions in time and efficiency of the rig crews are satisfactory in the opinion of the DS. Thereafter the frequency should be twice per week per crew for routine training.

1.2 Action Plan

<table>
<thead>
<tr>
<th>Action</th>
<th>Action By</th>
</tr>
</thead>
<tbody>
<tr>
<td>a) The float in the mud tank shall be raised or lowered. This simulates the case of the well &quot;Coming In&quot; or &quot;Losing&quot; returns.</td>
<td>DS</td>
</tr>
</tbody>
</table>
| b) Call alert, stop rotary, pull Kelly bushing above table to the required level of DP tool joint as per Drawing in the doghouse and stop pump. Observe well. Notes:  
(1) Steps a) & b) should take 1-2 mins.  
(2) Assistant Driller - takes position at the choke manifold. Floorman takes position on floor.  
(3) Derrickman + Mud Engineers - On Mud Tanks. | Driller |
| c) Open the hydraulic valve to the choke manifold. | Driller |
| d) Driller closes the Bag Preventer. | Driller |
| e) Report as soon as possible about tank levels. | Derrickman |
| f) Note the casing pressure and SIDP pressure (for hard shut in) Notes:  
(1) Steps c), d) and f) take 1-2 mins.  
(2) Total time from alarm to shut-in: 2-4 mins. | Rig Manager |
| g) Report timings in the I.A.D.C. report. When the ADCO Representative is satisfied that these timings are fast enough, this drill must be performed once per week. | Rig Manager |
| h) Report the drill on Weekly Kick Drill operating and Emergency Record and on the Morning Report, using code number only. | DS |
2. Kick Drill While Tripping - Code No. D2

2.1 Frequency

This drill will also be held once per week per crew as soon as the BOP stack is installed on each well, until every crew member is familiar with the entire operation and the timings are in the acceptable limit.

It may be held at any time the pipe is in casing and it shows the reaction of the driller and crew to the threat of a Blowout with the open drillpipe or collars in the hole.

2.2 Action Plan

<table>
<thead>
<tr>
<th>Action</th>
<th>Action By</th>
</tr>
</thead>
<tbody>
<tr>
<td>a) The float in the mud tank shall be raised for simulating the start of kick.</td>
<td>DS</td>
</tr>
</tbody>
</table>
| b) Call alert and observe well for flow.  
**Notes:**  
(1) Steps a) & b) should take 1 minute.  
(2) Assistant Driller - stands by Choke manifold.  
(3) Floormen to remain on floor.  
(4) Derrickman to remain in Monkey-board. | Driller |
| c) Close annular preventor. | Driller |
| IMPORTANT:  
For real kick with bit close to surface, the decision should be made immediately to RIH as close as possible to bottom after Step b) (if flow still permits). For this kick drill we assume well is flowing too much, and BOP is to be closed immediately. | |
| d) Make up kelly on safety valve. Open safety valve and record shut-in casing pressure and SIDPP.  
**Notes:**  
(1) Steps c) to d) should take 2-4 minutes.  
(2) Total time from alarm to shut in 3-5 minutes.  
(3) It is dangerous to close a pipe ram around DP with the string set in the slips, because of possible misalignment between the rotary table and the BOP stack. | Rig Manager on Choke Controls and Driller on Safety Valve |

Important in case of real kick only

- In case of real kick, DIPV dart must be pumped down its seat prior to stripping down through annular preventer.
• Once the DIPV dart is latched into its seat, do not forget to remove safety valve at the top of the string prior to stripping down the hole.

<table>
<thead>
<tr>
<th>Action</th>
<th>Action By</th>
</tr>
</thead>
<tbody>
<tr>
<td>After drill is completed wash choke lines thoroughly with water.</td>
<td>Driller</td>
</tr>
<tr>
<td>If any misalignment is observed between BOP and rotary table this must be adjusted immediately.</td>
<td>Rig Manager</td>
</tr>
<tr>
<td>The time taken from 'float raised' to ready to strip in hole will be reported in the I.A.D.C. Report.</td>
<td>Rig Manager</td>
</tr>
<tr>
<td>Record the drills performed on the Morning Report, using Code No. only and on Weekly Drill Emergency Record form.</td>
<td>DS</td>
</tr>
<tr>
<td>Prior to resuming normal operations, close the hydraulically operated valve, and ensure that choke line and manifold valves are returned to their correct trim.</td>
<td>Driller</td>
</tr>
</tbody>
</table>


3.1 Frequency

Twice a week as soon as the BOP stack is installed, on each well.

3.2 Action Plan

This operation is more a functional test rather than a "drill". It consists of:

<table>
<thead>
<tr>
<th>Action</th>
<th>Action By</th>
</tr>
</thead>
<tbody>
<tr>
<td>a) Bleeding off the accumulator pressure by opening slightly the accumulator by-pass valve until the Accumulator &quot;Mano-contact&quot; &quot;switches ON&quot; the accumulator pump. This should happen at 2800 psi in case of a 3200 psi WP unit or at 4800 psi in case of a 5200 psi WP unit.</td>
<td>Rig Manager and Chief Mechanic or Chief Elec.</td>
</tr>
<tr>
<td>b) Observing the re-building of the accumulator pressure after closing of the by-pass valve. The accumulator pump should &quot;SWITCH-OFF&quot; automatically as soon as the accumulator pressure reaches its maximum 3000/3200 psi or 5000/5200 psi, whichever unit is in use.</td>
<td>Rig Manager</td>
</tr>
<tr>
<td>c) Should there by any discrepancy in the minimum and maximum Switch On/OFF pressures, the Mano-contact sensor should be re-adjusted immediately to the required values.</td>
<td>Chief Mechanic or Chief Electri.</td>
</tr>
<tr>
<td>d) Report results of this drill in the I.A.D.C. Report.</td>
<td>Rig Manager</td>
</tr>
<tr>
<td>e) Report the drill on Weekly Kick Drill Emergency Record form and in Morning Report, using Code No. only).</td>
<td>DS</td>
</tr>
</tbody>
</table>
4. Well Kill Drill - Code No. D4

IMPORTANT:
This drill is made for the purpose of training rig crews in controlling/killing a Kick, by using the remote choke control, or the manual choke control, to reduce the drillpipe pumping pressure while pumping a simulated kill mud down to the bit, as per the "BOTTOM HOLE BALANCED PRESSURE METHOD". It is therefore imperative to be able to read the drillpipe pumping pressure directly on the manual choke by means of a pressure gauge installed on the choke manifold itself, as well as on the rig floor driller consul and remote control panel.

4.1 Frequency

Twice per well per crew before drilling the shoe of 13.3/8" and 9.5/8" casing string.

4.2 Outline of Drill

First conduct slow pump rate check at 30 and 45 SPM. Then calculate a kill mud weight supposing 300 psi SIDPP and 200 psi safety factor.

Prepare the pumping schedule based on a kill rate equal to the previously checked slow pump rate.

After calculations are complete and while circulating in casing activate the pit level alarms and shut in the well. Build up the assumed SIDPP with the pump and pump the simulated kill mud by choke adjustment according to the pumping schedule. Do not mix, nor pump any kill mud down the pipe. The pumping of the "Kill mud is true but the killing weight is only imaginary. Finish the drill when the simulated kill mud has reached the bit depth.

4.3 Calculations (to be made before-hand)

- Conduct "slow pump" rate check at 30 and 45 SPM with both pumps separately. Record corresponding pumping pressure for each pump, say:
  - Pump No.1 at 30 SPM = 400 psi
  - Pump No.2 at 30 SPM = (should be the same as No.1, if same liner size is used.)

- Record a shut-in drillpipe pressure (SIDPP) of say: 300 psi.
  **Note:** Do not consider any gain in volume for ease of calculations.

- Calculate the required kill mud weight by assuming:
  - Bit depth (suppose to be at 9.5/8" casing shoe) = 8350 ft
  - Mud weight in hole = 69 pcf
- Required overbalance at shoe depth = 200 psi

- Calculate the initial pumping pressure and the final pumping pressure at above supposed kill rate of 30 strokes per minute.

- Prepare a pumping schedule.

Notes:

1) The Drilling supervisor and the Rig Manager must use a separate worksheet, make calculations and pumping schedules separately, then check and agree on the figures.

2) With a view to minimize rig shut-down time during the drill, the above calculations, the pumping schedules and the final agreement on the figures to be used for the drill, will be made beforehand (in a "real kick" condition this would, of course, not be possible).

![Diagram of Kill Drill Pumping Schedule]

Required Kill Mud = \( \frac{69 \times 8356}{144} + 300 \times (\text{SIDPP}) + 200 \times \text{(Overbalance)} \times \frac{144}{8356} \) = 77.6 pcf

String Capacity = 1850 Stroke (to be calculated exactly)

Initial Pumping Pressure = 400 psi (SPR) + 300 psi (SIDPP) + 200 psi (overbalance) = 900 psi

Final Pumping Pressure = \( \frac{400 \times \text{SPR}}{69 \text{ pcf}} \times 77.6 \times \text{pcf (Kill Mud)} = 449 \text{ psi} \)
4.4 Action Plan

<table>
<thead>
<tr>
<th>Action</th>
<th>Action By</th>
</tr>
</thead>
<tbody>
<tr>
<td>a) After tagging the casing landing collar, conduct the slow pump rate at 30 SPM or 45 SPM as said above.</td>
<td>Driller</td>
</tr>
<tr>
<td>b) Raise the float in the active mud pit to activate the pit alarm on the rig floor and record the time.</td>
<td>DS</td>
</tr>
<tr>
<td>Note: On some rigs where the mud pit floats cannot be raised manually (electrical type of pit level recording) the DS will activate the pit level alarm by turning the adjustment knob directly on the “Pit-O-Graph” at the rig floor.</td>
<td></td>
</tr>
<tr>
<td>c) Make flow check by raising the kelly bushing to get the tool joint conveniently above the rotary table as per Drawing in the dog-house and stop pump. Assume flow.</td>
<td>Asst Driller Driller</td>
</tr>
<tr>
<td>d) Shut-in well</td>
<td>Driller</td>
</tr>
<tr>
<td>i) Close the bag preventer</td>
<td></td>
</tr>
<tr>
<td>ii) Open the hydraulically operated choke line valve.</td>
<td></td>
</tr>
<tr>
<td>e) Build up the 300 psi assumed SIDPP with the rig pump, to simulate a real SIDPP.</td>
<td></td>
</tr>
<tr>
<td>f) Kill the well by adjusting the casing (annulus) pressure constant at SICP while steadily and slowly increasing the pump to kill rate to pump simulated kill mud down DP (assume 30 SPM as said above) by opening the choke.</td>
<td>Rig Manager on Choke Driller at Pump Controls</td>
</tr>
<tr>
<td>i) When kill rate is reached, adjust the choke to give the calculated initial pump pressure on DP as per Kill Drill pumping schedule example given on Page 102.</td>
<td>DS Co-ordinating Derrickman</td>
</tr>
<tr>
<td>ii) Keep the pump rate constant throughout the kill.</td>
<td></td>
</tr>
<tr>
<td>iii) Follow the pumping schedule pressure steps by adjusting the choke.</td>
<td></td>
</tr>
<tr>
<td>iv) Have Derrickman operate Degasser.</td>
<td></td>
</tr>
<tr>
<td>g) End the drill when the imaginary kill mud has reached the bit depth.</td>
<td></td>
</tr>
<tr>
<td>h) Reporting of the drill will be as follows:</td>
<td>Rig Manager</td>
</tr>
<tr>
<td>i) Enter the drill details in the I.A.D.C. Report.</td>
<td>DS</td>
</tr>
<tr>
<td>ii) The ADCO Drilling Supervisor will fill in the kill drill report form and the Weekly Kick Drill Emergency record form. The DS will also report this drill on the Morning Report using the Code No. only).</td>
<td></td>
</tr>
</tbody>
</table>

Notes:
- As there is no actual kick fluid in the annulus the SICP will equal the SIDPP.
- For a real kick after closing the bag preventer the pipe should be reciprocated occasionally to reduce chances of stuck pipe.
- Calculate maximum allowable casing pressure while killing well based on 60% of internal yield strength of casing. For emergencies never exceed 80% of casing yield strength.
5. PVT Test - Code No. O1

5.1 Frequency

Daily check and each time D1, D2, or D4 are carried out.

5.2 Action Plan

<table>
<thead>
<tr>
<th>Action</th>
<th>Action By</th>
</tr>
</thead>
<tbody>
<tr>
<td>a) Raise and lower pit level floats to check alarm settings and alarm signals. The alarm settings will have to be constantly adjusted for variable tank level. <strong>Note:</strong> Any repairs must be carried out immediately</td>
<td>DS</td>
</tr>
<tr>
<td>b) Record the test in I.A.D.C. Report.</td>
<td>Rig Manager</td>
</tr>
<tr>
<td>c) Record the test in Morning Report, using Code No.01 only and also on the Weekly Drill operating and Emergency Record form.</td>
<td>DS</td>
</tr>
</tbody>
</table>

6. Degasser - Code No. O2

6.1 Frequency

Once per week on development wells or daily on Exploration wells, during each D4 Drill and prior to each DST on any well.

6.2 Action Plan

<table>
<thead>
<tr>
<th>Action</th>
<th>Action By</th>
</tr>
</thead>
<tbody>
<tr>
<td>a) Run the compressor and centrifugal pump. Check that fluid valves are open on both suction and discharge sides. Check for vacuum. <strong>Note:</strong> Any repairs must be carried out immediately.</td>
<td>Rig Manager</td>
</tr>
<tr>
<td>b) Record test in I.A.D.C. Report.</td>
<td>Rig Manager</td>
</tr>
<tr>
<td>c) Record the test in Morning Report, using Code No. 2 only and also on the Weekly Drill operating and Emergency Record form.</td>
<td>DS</td>
</tr>
</tbody>
</table>
Abu Dhabi Company for Onshore Oil Operations
Drilling Division
WELL KILL DRILL REPORT
Rig

................
.........

Last Casing

Well

...............

Shoe (MD)

. . . . . . . . . ft

Date

.................

Shoe (TVD)

TIMING
Alarm
Preventer & Chock Closed
Time to shut in well = . . . . . . . . Mins
From starting to pump kill mud
Kill mud at shoe depth
Time to pump kill mud to shoe depth (at . . . . . SPM) = . . . . . Mins

. . . . . . . . . . ft

at . . . . . . . . Hr
at . . . . . . . . Hr
at . . . . . . . . Hr
at . . . . . . . . Hr

EQUIPMENT CHECK
Yes

No

Float Setting – ok?
Float Alarm Buzzer – OK?
Pressure gauges (Do readings agree at SIDPP)?
Driller’s Console Drillpipe . . . . . . . . . . psi
Casing . . . . . . . . . . . psi

Standpipe manifold . . . . . . . psi

Chock Panel (Rig floor) DP . . . . . . . . psi
Casing . . . . . . . . psi

Chock manifold DP . . . . . . . psi
Casing . . . . . . . psi
Yes

No

SPM Readout – OK?
SPM Totalizers – Do readings agree at end of Drill?
Drillers panel . . . . . . . . Strokes
Chock panel . . . . . . . . Strokes
Geolographe – OK?
PVT recorder – OK?
Is communication OK between chock panel (RM)
and driller’s position?
and Chock manifold?
Degasser – OK?
Comments: . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . .
. . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ..
ADCO Co-Man

Rig Manager

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SECTION 1

BIT AND MUD MOTOR HYDRAULICS

1. LandMark Well Plan Hydraulic Model

The LandMark WELLPLAN Software is the standard engineering tools available for all ADCO’s Drilling engineers to use while planning and designing wells. The Hydraulic Analysis Model must be used to stimulate the dynamic pressure losses in the rigs circulation system, and to optimize bit hydraulics at a flow rate that gives the optimum motor power output.

Drilling hydraulics is optimized based on:

- Maximum hydraulic horse power
- Maximum impact force
- Maximum nozzle velocity
- Percent pressure loss at bit
- Flow rate requirements
- Differential pressure across motor or MWD for optimum performance.

The objective is to choose bit /rotor nozzles and BHA configuration that will allow one or more of the above to be achieved.

In other words, optimization of bit or motor hydraulics is often compromised by other hydraulic requirements such as hole cleaning requirements and the pressure drops / flowrate restrictions associated with certain pieces of downhole equipment.

The well plan hydraulic analysis model can be used to perform the following hydraulic modes.

- Calculate the actual pressure and ECD that will occur when the work string is tripped in or out of the hole.
- Examine the effects of changing flow rate and TFA on a number of hydraulics parameters.
- Calculate the flow rate and nozzle configuration to optimize bit hydraulics based on several common criteria.
- Determine nozzle configuration for optimal hydraulics using recorded rig circulating pressures. These calculations are based on Scott’s method, and uses only data specified on the input dialog.
• Calculate the amount of weight up or dilution material required to adjust mud weight to a specific value.

• Determine the cuttings concentration percentage, bed height, and critical transport velocity (low rate for a range of pump rates for all inclinations from 0 to 90 degrees (in five degree increments). This mode uses data specified on the input dialog, and does not use the current string, wellbore, or survey.

• Determine the cutting concentration percentage, bed height, and critical transport velocity flow rate in the wellbore using the current string, wellbore, fluid and survey. Use cutting transport model to evaluate cuttings build up in any hole section.

2. Optimizing Mud Motor Hydraulics

Mud motor performance can significantly be affected by the drilling system hydraulics. Motor speed and output torque is generally proportional to the flow rate and the differential pressure across the power section.

To optimize motor performance, some hydraulic factors in the system must be compromised, thus choosing the basis for hydraulic optimization must be carefully analyzed. I.e. optimizing flow rate while drilling top hole is of more importance than optimizing bit horsepower while, optimizing motor performance is of significant importance while drilling smaller hole size and harder formation intervals. Care should be taken to ensure that the hydraulic requirements at the planned final depth are considered.

The following are notes on optimizing motor hydraulics:

2.1 Operating Differential Pressure

Standby pressure with motor off bottom and standby pressure while motor is drilling on bottom.

2.2 Maximum Operating Torque

Is the torque delivered by the motor while drilling at the optimal operational differential pressure. It is not the stall torque, which can be considerably higher.

2.3 Maximum Bit Pressure Drop

Is the maximum pressure drop that can be tolerated by the motor before an unacceptably large flow passes through the bearings, causing a potential washout in the bearings. This value is not a recommendation of the bit pressure drop required for bearing balance of the motor, etc.
2.4 Minimum Bit Pressure Drop

Is the minimum pressure drop that can be tolerated, allowing enough flow bypasses through the bearing section for adequate cooling and lubrication.

2.5 Pressure Drop across the Motor

The pressure drop across the motor section is directly proportional to the drilling torque developed at the bit.

2.6 Rotational Speed

Depends primarily on the circulation rate, and is only slightly affected by the torque.

2.7 Maximum Allowable Mud Flow Rate

Each motor has a maximum allowable mud flow rate. If higher mud discharge is required, the motor allow a bypass flow through the center of the rotor. This bypass can be controlled by nozzle which is fixed by a nozzle holder on top of the rotor.

With a rotor nozzle installed, circulation rates in access of the nominal maximum value should be used only with the bit on bottom, excess flow off-bottom would be only partly bypassed, and can cause severe damage to the motor by over speeding by using a nozzle, the motor cannot deliver its full power even with higher flow rates.

Proper rotor nozzles size must be selected for optimum motor performance and hole cleaning.
SECTION 2

HOLE CLEANING GUIDELINES

The removal of cuttings from the wellbore is an essential part of the drilling operation. Efficient hole cleaning must be maintained. Failure to effectively transport the cuttings can result in a number of drilling problems including:

- Excessive overpull on trips.
- High rotary torque.
- Hole pack-off and stuck pipe.
- Formation break down.
- Slow ROP.
- Lost circulation.

All of these are potential problems for both near-vertical and higher angle wells. Generally, however, hole cleaning rarely presents a problem in near vertical wells. The problems listed above are more common in highly deviated wells.

Section 5.1 Summarizes hole cleaning practices with respect to hole inclination differences.

Section 5.2 Makes recommendations for flow rates when hole angle is greater than 35 degrees, and gives guidelines for circulation times prior to tripping.

1. Good Hole Cleaning Practices

- Clean the hole as fast as it is drilled. Circulate at sufficient GPM relative to ROP. Do not allow the penetration rate to exceed the ability to clean the hole. Use computer models to simulate potential conditions, and required flow-rate for expected ROP.

- Ensure mud is within specification. Rheology is very important for hole cleaning.

- Circulate clean prior to tripping. Bottoms-up does not ensure a clean hole. Use the circulation guideline in 8.3 Table 2. Always check that the shakers are clean before tripping.

- Maximize string motion when circulating hole clean.

- Plan and perform wiper trips as hole conditions dictate. Wiper trips help disturb cuttings beds further up the hole.

- Monitor the shakers. Both volume and type of cuttings are important indicators of hole condition. Know what to look for.

- Keep all circulating and solids control equipment in good working order.
2. Hole Inclination and Recommended Practices

<table>
<thead>
<tr>
<th>0 – 35 deg Inclination</th>
<th>35 – 60 deg Inclination</th>
<th>60 – 90 deg Inclination</th>
</tr>
</thead>
<tbody>
<tr>
<td>Vertical and low angle wellbores, cuttings move up with fluid. Viscosity lifts cuttings. Backreaming, or slide drilling do not cause hole cleaning problems</td>
<td>Cuttings move up the hole mostly on low side. Can be stirred up into flow regime. When pumps are turned off, cuttings will avalanche down until angle is too high. Dunes form easily</td>
<td>Cuttings move out on low side. Mechanical agitation required, regardless of flowrate or viscosity of mud. With pumps off cuttings immediately fall on low side. No avalanching, but hole cleaning is more time consuming</td>
</tr>
<tr>
<td>Must be remembered: This type of well also has 0 – 35 deg inclination sections</td>
<td>Must be remembered: This type of well also has 0 – 60 deg inclination sections</td>
<td></td>
</tr>
</tbody>
</table>

Flow rate:
- As high as practical
- With motor, if pressure limited, can circulate higher when off-bottom (off-bottom pressure loss is lower) eg. When circulating hole clean (provided motor circulating limits are not exceeded).

Pipe Rotation
- Drill string rotation has little hole cleaning effect on near vertical wells
- No hole cleaning problem during sliding
- Critical
- Recommended minimum 100 – 120 rpm
- Preferable 150 – 180 rpm
- Limited/no hole cleaning when sliding
- Minimize slide lengths
- With motor and bent housing, can theoretically rotate string at higher RPM when off-bottom

Cleanup practices
- Normal “bottoms up” or until shakers are clean approach
- For vertical holes, reciprocate rather than rotate pipe
- Prior to POOH circulate with max available flowrate and max allowable pipe RPM while working last stand/joint on bottom.
- Pipe rotation should be at least above 120 RPM (preferably above 150 RPM)
- Circulation and rotation should continue until hole cleans up (shakers clean)
<table>
<thead>
<tr>
<th>Inclination</th>
<th>General Tripping practices</th>
<th>General Tripping practices</th>
<th>Working Past ledge or Keyseat</th>
</tr>
</thead>
<tbody>
<tr>
<td>0 – 35 deg Inclination</td>
<td>• Tight hole in vertical wells and low angle wells is likely due to wellbore conditions</td>
<td>• Clean hole as stated</td>
<td>• Slow rotation (less than 80 rpm) can be used in an attempt to “walk” pipe past ledge</td>
</tr>
<tr>
<td></td>
<td>• Backreaming and/or pumping out can be carried out as required with low risk.</td>
<td>• POH no pumps/ no rotation</td>
<td>• Work up to agreed overpull limit in stages ensuring free movement in either direction</td>
</tr>
<tr>
<td>35 – 60 deg Inclination</td>
<td></td>
<td>• Firstly assume tight spots are due to cuttings beds. RIH until well clear of obstruction. Circulate and rotate as per cleanup practice, for 30 min.</td>
<td>• Try limit overpulls to half of BHA weight in order to avoid getting stuck.</td>
</tr>
<tr>
<td>60 – 90 deg Inclination</td>
<td></td>
<td>• If BHA cannot move down (eg. bit near bottom), gradually start rotation, then bring on pumps slowly.</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>• POOH without pumps.</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>• No tight spot or tight spot has moved up, implies cuttings beds.</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>• If tight spot is in same place, could be ledge or key-seat, follow instructions below.</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td><strong>Backreaming</strong></td>
<td><strong>Backreaming</strong></td>
<td><strong>Pumping Out</strong></td>
</tr>
<tr>
<td></td>
<td>• Not preferred option</td>
<td>• Not recommended</td>
<td>• Can be performed as necessary</td>
</tr>
<tr>
<td></td>
<td>• But should not cause hole cleaning problems if backreaming is necessary</td>
<td>• Risk packing off</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Risk damage to wellbore</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>• If backreaming is necessary, it should always be performed at max allowable flowrate and at maximum possible RPM</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Control backreaming speed (4 stands/hour can be used as a rule of thumb for maximum speed)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>• After extensive backreaming, cleanup hole before POOH as per Cleanup practice.</td>
<td></td>
</tr>
<tr>
<td></td>
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<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td><strong>Pumping Out</strong></td>
<td><strong>Pumping Out</strong></td>
<td><strong>Connections</strong></td>
</tr>
<tr>
<td></td>
<td>• Can be performed as necessary</td>
<td>• Not recommended (unless high swab risk exists)</td>
<td>• Before making a connection, circulate at normal flow rate to clear cuttings from around BHA (5 – 10 minutes)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Pumping out just creates dune above BHA</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Provides no hole cleaning ability in a high angle wellbore (no string RPM to stir up cuttings)</td>
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</tr>
</tbody>
</table>
3. Flow Rate and Circulation Guidelines

3.1 Flow Rate

The following are minimum recommended flow rates for wells with inclination greater than 35 degrees.

Table 4-1: Estimated annulus velocity

<table>
<thead>
<tr>
<th>Hole Size</th>
<th>GPM</th>
<th>Annular Velocity, Across DP Section</th>
</tr>
</thead>
<tbody>
<tr>
<td>26&quot;</td>
<td>Maximum possible</td>
<td></td>
</tr>
<tr>
<td>17 1/2&quot;</td>
<td>1000</td>
<td>87 ft/min</td>
</tr>
<tr>
<td>12 1/4&quot;</td>
<td>800</td>
<td>156 ft/min</td>
</tr>
<tr>
<td>8 1/2&quot;</td>
<td>650</td>
<td>338 ft/min</td>
</tr>
<tr>
<td>6&quot;</td>
<td>450</td>
<td>450 ft/min</td>
</tr>
</tbody>
</table>

3.2 Circulation Guidelines

Use the following guidelines for the circulation time prior tripping:

Table 4-2: Section length factor for different inclination

<table>
<thead>
<tr>
<th>Well Inclination</th>
<th>17 1/2&quot;</th>
<th>12 1/4&quot;</th>
<th>8 1/2&quot;</th>
<th>6&quot;</th>
</tr>
</thead>
<tbody>
<tr>
<td>0° – 10°</td>
<td>1.5</td>
<td>1.3</td>
<td>1.3</td>
<td>1.3</td>
</tr>
<tr>
<td>10° – 35°</td>
<td>1.7</td>
<td>1.4</td>
<td>1.4</td>
<td>1.4</td>
</tr>
<tr>
<td>35° – 60°</td>
<td>2.5</td>
<td>1.8</td>
<td>1.6</td>
<td>1.5</td>
</tr>
<tr>
<td>60° +</td>
<td>3</td>
<td>2</td>
<td>1.7</td>
<td>1.6</td>
</tr>
</tbody>
</table>

Table 2

Example for 17 1/2" hole at total depth 6000 ft and 60° inclination.

<table>
<thead>
<tr>
<th>Measure Length</th>
<th>Factor</th>
<th>Effective Length</th>
</tr>
</thead>
<tbody>
<tr>
<td>2000 (0° – 10°)</td>
<td>1.5</td>
<td>3000</td>
</tr>
<tr>
<td>1000 (10° – 35°)</td>
<td>1.7</td>
<td>1700</td>
</tr>
<tr>
<td>1000 (35° - 60°)</td>
<td>2.5</td>
<td>2500</td>
</tr>
<tr>
<td>2000 (60° +)</td>
<td>3</td>
<td>6000</td>
</tr>
<tr>
<td>Total 6000</td>
<td></td>
<td>Total 13200</td>
</tr>
</tbody>
</table>
To calculate circulation volume, divide well into sections as per the inclination intervals.

Number of cycles required = Total Effective Length/Measured Depth
= 13,200 / 6,000 = 2.2 cycles

4. Remember

- Holes between 30 and 60 degrees inclination are the hardest to clean due to the formation of unstable solids beds on the low side of the hole. These unstable beds can "avalanche" down the hole.

- At greater than 60 degrees inclination stable beds form which are very difficult to remove without some mechanical action. Pipe rotation is ideal for this even when only slow rotation is possible.

- If no other guide to the minimum annular velocity is available, then a rule of thumb is to try to maintain a minimum of 45 m/minute. The best guide to hole cleaning is what you see on the weight indicator and shakers.

- Balanced combination pills are very effective for sweeping the hole. A low viscosity low density pill is followed by a high viscosity high density pill. Pumping must be continuous while the pills are in the hole. Make sure the low density pill does not underbalance the well at any stage (eg when opposite the BHA).

- If possible rotate and reciprocate the string while circulating clean. The reciprocation stroke should be greater than the length of a single to avoid building ridges on the low side of the hole.

- Solids beds move up the hole far slower than the fluid velocity in the middle of the largest part of the annular space, perhaps 3 to 5 times slower. This means that extra circulating time is needed when cleaning the hole.

- Initial overpull when tripping should be limited to 20,000 to 30,000 lb (no rotation or circulation) if a hole cleaning problem is suspected. If this limit is reached more hole cleaning should be considered prior to pulling out of hole.

- Good drag charts are essential for spotting problems early.
SECTION 3
TORQUE AND DRAG OPTIMIZATION

1. Basic Principles


The friction force (F_f) comprises 3 parameters:

- Normal Force (F_n)
- Friction Factor (μ)
- Direction of friction force

Here it is necessary to revisit a basic law of physics, which describes the resistance to movement - the friction force - at a contact point in the wellbore:

\[ F_f = \mu \times F_n \]

The direction of the friction force is always directly opposed to the direction of movement, where movement is the combined effect of translation and rotation.

These three parameters are separately discussed below.

The string has many points of contact with the wellbore, e.g. tool joints, pipe body and stabilizers, which all generate a friction force. **Up/Down Drag** is, to a first approximation, the sum of the friction force along the wellbore, if the string is moved in an upward/ downward direction without rotation.

2. Normal Force

Let us consider a string element with a weight of W, consisting of a tool joint and half a joint of drillpipe at each side. The tension exerted on the ends of the element are \( T_{up} \) and \( T_{down} \).

The normal force is dependent on the rate of curvature, also called dogleg, and the magnitude of the tension:

In more simple terms, the `string gets pulled into the side of the hole', all the more so if there is a sharp dogleg and the tension in the string is high.
3. Friction Factor

The main parameters determining the friction factor are the formation type and the mud. In this context the casing is considered as ‘formation type steel’. The table below gives some feel for the relative magnitude of the friction coefficient.

<table>
<thead>
<tr>
<th>Friction Factor (µ)</th>
<th>Oil Based Mud</th>
<th>Water Based Mud</th>
</tr>
</thead>
<tbody>
<tr>
<td>Casing</td>
<td>LOW</td>
<td>MEDIUM</td>
</tr>
<tr>
<td>Shale</td>
<td>MEDIUM</td>
<td>VERY HIGH</td>
</tr>
<tr>
<td>Limestone</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Soft Sandstone</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hard Sandstone</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

It now becomes clear why it is so beneficial to case off the build-up section in a well: it provides a low friction factor environment in an interval with high normal forces.
4. **Direction of Friction Force**

Given a certain normal force and friction factor, the magnitude of the friction force is fixed. The effect of rotating the pipe is that the direction of movement changes, but not the magnitude of the friction force.

When there is no rotation, all of the frictional load, or force, is in the direction of movement, for example, up or down along the length of the borehole. When rotating, most of the frictional load is in the circumferential direction leaving very little to oppose axial motion of the pipe. There are important implications in drilling; for example, its why in a deviated well, a greater measured depth can be reached by rotating before approaching the minimum yield load of the drillstring, and why drill string buckling point is reached much sooner when sliding than when rotating.

5. **Torque and Drag Modeling**

Torque and Drag modeling uses the above described fundamentals, to describe forces in a highly complex drilling environment.

Two distinct types of Torque and Drag modeling are commonly used: Soft String, and Stiff string models. The results obtained with the Soft String model for wellbores with dogleg severities of less than approximately 10 degrees per 100 ft are very similar to those determined with a Stiff String model. For borehole curvatures larger than 10 degrees per 100 ft, the results cannot be compared any more, hence, it is strongly recommended that you apply a Stiff String model.

The following are some of the more important suggested uses for Torque and Drag modeling in drilling operations:

| To assist in planning | • Rig surface torque requirements for top-drive/rotating table.  
|                       | • Rig overpull capacity.  
|                       | • Rig power requirements (surface torque, drawworks). |
| To optimize drilling operations by studies of parameters | • Well profile optimization.  
|                                                           | • Drillstring / completion string configuration.  
|                                                           | • BHA design. |
| To help understand downhole conditions | • Adjust friction factors to match real and calculated surface data.  
|                                               | • Compare pick-up, slack-off, and off bottom rotating measurements. |
| To analyze the down-hole forces and stresses on the string | • Maximum WOB that can be applied.  
|                                                              | • Yield stresses on the string.  
|                                                              | • Fatigue stresses endurance limit.  
|                                                              | • String extension.  
|                                                              | • Torque distribution.  
|                                                              | • High wall forces leading to casing wear, keyseating, and high torque. |
6. Ways to Minimize Torque and Drag

6.1 Well Profile Design

Well profile design to minimize torque and drag involves minimizing wallforces. Since string tension is always highest at surface (which can lead to high wallforces as described above), the way to minimize wallforces is to minimize doglegs (build rates) at surface, and to build angle towards the target further downhole where string tension will be less. This is achieved by drilling the well with a tangent angle as close to the critical sliding angle as possible, causing the string to "glide" under its own weight.

Well profile design is also a compromise meeting a large variety of requirements, of which torque and drag minimization is just one factor. For conventional wells (low reach/TVD ratio), "under-section" profiles (which have a deep KOP) are better because they give tangent angles closer to the critical sliding angle. In contrast, the "build and hold" profile causes higher tension, hence torque and drag. In ERD wells however (high reach/TVD ratio), a high kick off point will be required to provide the critical sliding angle in the tangent section.

Note that in deep wells, it is particularly important to drill the top sections as smoothly as possible to minimize the torque contribution from tortuosity. Excessive use of steerable assemblies can worsen tortuosity, rotary assemblies or straight hole drilling devices are beneficial.

6.2 Water Based Muds

The coefficient of friction will depend on the formation type being drilled. For water based muds where shale softening is possible due to poor inhibition, decreased values of friction may be observed. In hard sandstone etc. higher values of friction may be observed for an identical mud system.

Baryte improves lubricity when used in weighted systems possibly due to the formation of a soft "bearing layer" modifying the surface contacts. Above ca. 1.2 to 1.3 sg baryte promotes reduced coefficients of friction.

Polymers in water based muds can have a beneficial effect on lubricity - partially hydrolysed polyacrylamide (PHPA) can exhibit a friction reducing effect.
The coefficient of friction is less for a steel/steel contact than a steel/rock contact (cased hole has a lower coefficient of friction than open hole.

A wide variety of lubricants are available for addition to water based mud systems. All show different performance features in reducing the coefficient of friction. They are of benefit in low mud weight systems but less benefit in high mud weight systems.

### 6.3 Oil Based Muds

In the laboratory and in the field, oil based mud systems exhibit lower values of friction than water based mud systems. By virtue of its film forming capacity, oil is intrinsically a better lubricant than water, however, the presence of strong surfactant packages in an oil based mud system may also aid the lubricity effect.

The positive effect of baryte is less pronounced for oil based muds but oil/water ratio does noticeably affect lubricity: lubricity decreases as the water content of the oil mud is increased.

The coefficient of friction value measured in laboratory tests is comparable for metal-metal and metal-sandstone contact. As with water based mud, it is still observed that cased hole has a lower coefficient of friction than open hole.

Some of the new synthetic oil mud systems demonstrate better lubricity than those formulated with mineral oil.

So far, lubricants in oil based mud have had little application, as OEM's are considered sufficiently lubricating. Water based mud lubricants are not effective in OBM. Solid lubricants (graphite powder and lubra beads (see below) are more effective.

### 6.4 Physical Methods

#### 6.4.1 Lubricating Beads

A commercially available product called Lubra beads (small glass spheres which function like ball bearings) has been used with some success resulting in torque reductions of up to 20%. Removal of the beads by cuttings handling equipment can be a problem. To get around this, the product can be used selectively to spot areas where high torque is occurring.

#### 6.4.2 Drillpipe Coatings

A small amount of work has been carried out looking at coatings which could be applied to steel to reduce the steel/steel friction coefficient. Hardbanding of tooljoints to reduce casing wear has also been
examined. Because of the extreme forces involved in drilling, the integrity of the coating remains an issue.

6.4.3 Drillpipe Protectors

Non-rotating drill pipe protectors (DPP's) have been shown to reduce torque by up to 30% in many ERD wells. A well proven tool is the Western Well Tool non-rotating stabilizer, although other tools are being developed. However, there are a number of downsides to their use:

- annular pressure loss is increased (up to 2 psi per tool, quoted in Norway)
- sliding ability is reduced
- durability still causes some problems
- their use is generally restricted to cased hole
- significant cost and installation/removal time

Their use should therefore, be optimized by placing them in areas of highest wallforce. Wallforce should be calculated with Torque and Drag modeling to determine optimum placement and the number per joint required.

6.4.4 Bearing Subs

Bearing subs may be used in open hole where DPP’s are not suitable. The DBS bearing sub has been successfully trialed. Again, sliding may be hindered in very high angle wells. Time for make up and cost, must also be considered.
1. Basic Concepts

Before discussing drilling parameter practices, and guidelines for drilling optimization, a review of the basic concepts in relation to Weight Indicator, Torque and Limits is beneficial. Reference : ABC of Stuck Pipe, Shell U.K. Exploration and Production.

1.1 Weight Indicator

The weight indicator, often referred to as the `Martin Decker', is the most important instrument for the driller in terms of drilling optimization, and avoiding stuck pipe. It measures the weight hanging from the crown block, provides clues to what is happening downhole, and allows him to operate within the limits of the equipment.

The following definitions are very important:

The value shown on the drillers weight indicator is defined as **Measured Weight**, and includes the weight of the Traveling Equipment.

The weights observed when moving the **String** down and up are shown in the diagram below:
The **Down Weight** is the measured weight under **Normal Hole Conditions** when moving the string in a downwards direction, without rotation and with the pumps shut off. The converse is **Up Weight**, i.e. when moving the string in an upwards direction.

Every driller is aware of the fact that the up weight reduces and that the down weight increases when he starts rotating the string. (More details in Section 6: Torque and Drag Optimization). The measured weight while rotating off bottom without reciprocating is called **Rotating Weight**.

**Down Drag** is the difference between the down weight and rotating weight, whilst the difference between the up weight and rotating weight is called **Up Drag**.

Particular care is required when the measured weight is lower than the down weight or higher than the up weight, because some form of restriction is then being encountered. In the former case, the difference between the measured weight and the down weight is called **Setdown**, while in the latter case the difference between the up weight and measured weight is referred to as **Overpull**.

### 1.2 Torque

The value shown on the driller's torque indicator is defined as **Measured Torque**. **Off Bottom Torque** is measured when rotating with the string off bottom.

**Drilling Torque** is the measured torque while drilling under normal hole conditions. Increases over the drilling torque are referred to as **Incremental Torque**.

### 1.3 Limits

**Maximum Pull Limits**

The upper limit of the measured weight is called **Maximum Allowable Measured Weight**. It is determined by the minimum of:

- The strength of the string (85% of pipe body yield strength corrected for torque).
- The pulling limit of the hoisting equipment.

Additional forces when jarring must be taken into account.

**Minimum Pull Limits**

The lower limit of measured weight is called **Minimum Allowable Measured Weight**, which is achieved:
• At the onset of plastic buckling deformation of the string.
• By slacking off the entire weight of the string if the plastic buckling limit is not reached.

Note that the limit for buckling in a stuck pipe condition, i.e. without rotation, is much lower than with rotation. In the latter case a large allowance is made for fatigue.

1.3.1 Torque Limits

The upper limit of right hand measured torque is determined by the lowest of:

• Maximum allowable torque on drill pipe, corrected for pull.
• Minimum make-up torque of any connection in the string.
• Maximum torque that can be generated by the rotary equipment.

2. Monitoring of Parameters

• Monitor closely penetration rate, rotary speed, torque, standpipe pressure and pump stroke rate. Do this while reaming as well as when drilling fresh hole. Ensure that the mud logging unit (or rig data system if appropriate) records all relevant parameters when drilling and when reaming.

• Continuously compare the observed drilling performance (penetration rate, torque, standpipe pressure) and cuttings interpretation with the prognosis for the well. Any discrepancies between the observed and anticipated performance should be evaluated and explained.

• Use the characteristics for different drillability problems to diagnose the probable cause of any lower-than-anticipated penetration rate. Changes in torque can aid the diagnosis of many drillability problems.

• Irregular torque can indicate interbedded formations, stabilizers hanging-up, keyseats or doglegs, excessive weight on bit, bit going undergauge, junk in hole.

• Increased torque may be due to higher weight on bit, formation change (softer, higher porosity), increased inclination, thicker filter cake (potential for differential sticking), roller cone bit bearing failure, bit going undergauge or kick.

• Reduced torque may be due to lower weight on bit, formation change (harder, lower porosity), running on a dislodged drill pipe rubber, cutting structure wear/damage, bit or bottom balling.

• Standpipe pressure should normally be steady and should increase slowly with increasing hole depth. Increases in standpipe pressure may be due to annulus packing-off / stabilizers balling up, global balling of the bit body, ring-out of a PDC
bit, inadequate hole cleaning, plugged nozzle or fluid passageway in bit, PDM running at higher torque, mud viscosity increasing.

- Decreases in standpipe pressure may indicate a washout in the string, a lost nozzle, lost circulation, aeration of the mud, lower torque at PDM, and wear/damage to downhole motor/turbine.

- However, increases in pump rate can have the same causes as falling standpipe pressure, decreases in pump rate can have the same causes as increasing standpipe pressure.

3. **General Parameter Optimization**

- Operate at the weight on bit and rotary speed that give the highest penetration rate in the drill-off tests, unless significant drill string vibrations are seen.

- 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.

- Do not apply excessive weight on bit if bit or bottom balling have been identified as potential problems, or if a shale is to be drilled with a water-based mud.

- Keep the applied weight on bit smooth once it has been optimized. Feed weight continuously to the bit using the Driller’s electric brake (Elmago, Baylor etc) and avoid "slack-off / drill-off" - this can contribute to damaging torsional vibrations.

- The maximum allowable penetration rate, beyond which the ECD increases due to cuttings loading in the annulus exceeds the leak-off pressure, should be calculated if the penetration rate is high. Reduce the applied weight on bit and/or rotary speed as necessary to ensure that the penetration rate does not exceed the maximum allowable.

4. **Monitor in Mud Gas**

Be aware and fully appreciate that it is imperative that the gas levels in a drilling mud are correctly interpreted and the definitions are strictly adhered to. This is particularly critical during tripping operations.

Pore pressure, or certain potential kick situations, can only be assessed accurately on the basis of observations of trip gas, connection gas, swab gas and pump off gas. If any of these are observed then pore pressure levels are close to mud hydrostatic.

Increasing background gas levels can indicate increasing pore pressure if correctly determined and analysed - it is important that the drilled gas level content of background gas is understood.

For definition purposes the level of gas in the mud is due to one or a combination the following:-
• **Background Gas:** The general level of gas carried by the mud purely as a function of circulating in open hole.

• **Drilled Gas:** Gas which has entered the mud due to the actual drilling of the formation, i.e. the gas contained in the matrix of the rocks which have been drilled.

• **Connection Gas:** The gas which enters the mud when a connection is made due to reduction in hydrostatic due to loss of ECD and due to swabbing while pulling back.

• **Swabbed Gas:** The gas which enters the well due to swabbing. This may be caused by tripping or by simulating tripping.

• **Trip Gas:** The gas which enters the mud during a trip which is measured after a trip has taken place.

• **Pump Off Gas:** The gas which enters the mud due to turning off the mud pumps and removing ECD from the hydrostatic pressure on the bottom of the well.

5. **Monitoring of Cuttings**

• Cuttings samples should be collected regularly at the shakers.

• The collected cuttings should be examined and interpreted promptly after collection.

• They will confirm an expected formation change or indicate an unexpected formation change, can aid the interpretation of penetration rate and torque changes, and can help discriminate between different causes of reduced penetration rate, e.g. bit wear versus harder rock.

• The presence of large cavings can indicate mechanically induced wellbore instability problems and may indicate an increase in pore pressure gradient. The shape of cavings can help identify the mechanism that caused them to enter the well. The appropriate corrective action is influenced by the caving mechanism.

• The presence of rubber in the cuttings often indicates problems with the downhole motor. The presence of metal in the cuttings can indicate problems with the bit or downhole motor, or damage to the wellhead, casing or downhole equipment.

• The lag time is the time for cuttings to be transported from the bit to the surface. The lag depth is the depth from which the cuttings originate, and not the bit depth when they reach the shale shakers. Both the lag time and depth should be calculated and updated as often as feasible, to avoid misinterpretation of the depth of the formation from which the cutting samples originated.
• The effects of high penetration rates and borehole instability on the depth resolution of cuttings should be considered when drawing conclusions from cuttings.

• The impact of over-gauge hole on lag time and depth should be considered if there is any potential for hole enlargement.

• Closely monitor shakers and cuttings volume trend, in order to assess hole cleaning.
SECTION-5

DRILL-OFF TESTS

1. General

Drill-off tests can help optimize drilling parameters (weight on bit and rotary speed) for maximum penetration rate.

- Run a drill-off test once a new bit has been broken in or when a significantly different formation is penetrated.
- Do not run a drill-off test with a new bit until it has been broken in, to avoid possible bit damage.
- Do not run a drill-off test if the penetration rate is already very high, as this makes a drill-off test difficult to perform.
- Do not run a drill-off test if the formation is very erratic, as the results may then be too scattered to be useful.
- Drill-off tests can be passive or active.

2. Passive Drill-off Test

- Pull off bottom to zero the weight on bit, and to remove any drag from the string.
- With moderate rotary speed, apply the maximum permissible weight on bit and chain the brake handle so that no more line is fed out and the traveling block remains at a fixed height above the rig floor.
- Monitor the weight on bit continuously.
- Record the time at which the weight has decreased by a fixed increment (5-50 kN, depending on bit type and size).
- Continue recording the times at which the weight has fallen by the same increment, until the penetration rate has fallen to well below the level at the start of the test.
- Identify the weight on bit range over which the time to drill off the increment was shortest. The optimum weight on bit at this rotary speed is in that range.
- Repeat the test procedure at several different rotary speeds, up to the highest permissible for the bit and drive system.
- The optimum combination of weight on bit and rotary speed will be those that give the shortest time to drill off the chosen increment of weight.
• A passive drill-off test may stop when significant weight on bit still shown on the weight indicator at surface.

• This can indicate poor weight transfer downhole.

• It does not indicate tooth wear on roller cone or PDC bit.

• It is possible to compute the instantaneous penetration rate from time/weight on bit data and knowledge of the drillstring compliance.

• The drillstring compliance is determined by the drillstring composition.

• Good quality weight on bit data, recorded at a frequency of at least 1 Hz is required.

• Some rig instrumentation packages provide passive drill-off test interpretation software.

3. Active Drill-off Test

An active drill-off test can identify the optimum weight on bit within the range indicated by a passive drill-off test.

• Set the rotary speed at the best value from the set of passive tests.

• Hold the weight at the low end of the optimum range indicated by the passive test, and record the penetration rate over 5 minutes.

• Repeat at several different weights up to the upper end of the optimum range indicated by the passive drill-off test.

• Similar active drill-off tests can be run without first running passive tests.

• Apply a weight on bit and a rotary speed that are in middle of the respective specified ranges.

• Hold these values and record the penetration rate for 5 minutes.

• Increase the weight, record the penetration rate; decrease the weight to below the initial level and record the penetration rate.

• Set the weight midway between the two values giving the highest penetration rates.

• Record the penetration rate over 5 minutes at higher and at lower rotary speeds.

• Select the rotary speed midway between the two giving the highest penetration rates.
SECTION 6

DRILLING VIBRATIONS

1. Stick Slip Vibration

- Procedures to avoid stick-slip vibration should be followed as soon as severe low-frequency torsional vibrations are observed - do not wait until full stick-slip motion has developed.
- Increase the rotary speed in 10 rpm increments until smooth running is re-established or until the maximum allowable for that bit and drive system is reached.
- If stick-slip persists, decrease the weight on bit progressively. Do not reduce the weight below the value at which smooth running is re-established.
- If the vibration amplitude does not decrease after increasing rotary speed and reducing weight on bit, the stick-slip is probably due to string friction.
- Increase the mud flowrate if possible without risking borehole and/or bit erosion.
- Make frequent wiper trips, if necessary, reaming back to bottom to ensure hole clean.
- If a water-based mud is in use, consider treating mud with lubricant additive in order to reduce string friction.
- If the rig is fitted with a soft-torque system, ensure that it is set up correctly and functioning as intended.
- If the above procedures do not cure stick-slip, consider changing the BHA/bit when the string is next tripped out of hole.

2. Axial Vibrations

- Be aware of the critical rotary speed(s) for the BHA that is in use.
- If axial vibrations are suspected to be occurring with a roller cone bit, adjust the rotary speed so that the rotary speed moves away from the critical rotary speed and/or one third of the critical rotary speed.
- If a fixed cutter bit is in use, adjust the rotary speed to move away from the critical rotary speed.
- If adjusting the rotary speed alone does not stop the vibration, or if the rotary speed is well away from the critical rotary speed, reduce the weight on bit.
• Adjust the individual mud pump stroke rates so that the pumps operate at different stroke rates while keeping the total flow rate unchanged.

• If severe axial vibrations occur, stop the rotary drive and pull the bit off bottom. Re-start the bit following the procedure given in Section 7.

• Follow negative drill-break practices if axial vibrations develop when drilling into a hard formation from a softer formation.

3. Lateral Vibrations

• If damaging lateral vibrations are suspected, stop the rotary drive, pull the bit off bottom and re-start following the procedure given in Section 7. Do not return to the same weight on bit or rotary speed.

• Run at a lower weight on bit, and adjust the rotary speed as described above in Axial Vibrations.

• Adjust the individual pump stroke rates so that the pumps operate at different stroke rates while keeping the total flow rate unchanged.

4. BHA Whirl

• Reduce the rotary speed if forward BHA whirl is suspected.

• If this does not stop the whirl, stop the rotary drive, pull the bit off bottom and re-start the bit following the procedure given in Section 7.

• Return to a lower rotary speed than that being used before pulling off bottom.

• If backward BHA whirl is suspected, stop the rotary drive, pull the bit off bottom and re-start the bit following the procedure given in Section 7.

• Return to a lower rotary speed than that being used before pulling off bottom.

• Consider treating mud with lubricant additive if high string torque is suspected of causing backward BHA whirl.

• Follow correct connection procedures (see Section 7).

5. Torsional Vibrations

When the drill string is rotated from the surface, the drill pipe is initially wound up like a spring, and the BHA does not rotate at all until the torque in the drill pipe is sufficient to overcome the static friction between the BHA and the borehole wall plus the torque required to rotate the bit.

When this torque level in the drill pipe is reached, the BHA and bit will start to rotate. Given that dynamic friction is less than static friction, as the BHA starts rotating the
resistance is reduced and the BHA will accelerate rapidly. It can gain so much angular momentum that it will catch up with and pass the rotation of the drill pipe, so that the driving torque from the drill pipe to BHA actually becomes negative. If this happens, the BHA will slow or come to a halt again.

The effect is, that while the rotary table or the top drive are rotating at a constant speed of say 100 rpm, the BHA can have instantaneous rotation rates of between zero and say 300 rpm. Filed measurements have shown that a temporary BHA rotary speed of 3 times the surface rotary speed is not unusual, and BHA speeds of up 10 times surface rotary speed occur occasionally.

Torsional vibrations are ‘self excited vibrations’, which means that there is no periodic excitation force. The drill string has a natural period of resonance which depends on its geometry, its mass, the friction with the bore hole wall, the drilling fluid viscosity etc. and the energy of the oscillation is derived from the rotary table.

The vibration can sometimes be recognized by a “humming” sound in the drive motor with a period of 1-10 seconds (0.1-1 HZ). There is not much one can do by changing operational parameters. The best cure for this vibration is the installation of a Soft Torque drive.

6. Coupling

Coupling effects complicate the identification and cure of drill string vibrations somewhat. For example, axial vibration can be caused by pump pressure fluctuation, whirl in a curved hole or MWD pressure pulses. With down-hole motor drilling there is a coupling between torsional and axial vibrations through the bit; whirl and torque fluctuations are also coupled.

Finally, as a general solution, if vibration problems cannot be sufficiently contained in rotary drilling, the use of down-hole motors should be considered.

7. Impact of Sulphide Stress Cracking Under Above Stress

Sulphide stress cracking (SSC) may occur in the presence of H$_2$S. In this mechanism, H$_2$S reacts with the iron in the drill pipe to form atomic hydrogen.

$$\text{Fe} + \text{H}_2\text{S} = \text{FeS} + 2\text{H}$$

Some of the free atomic hydrogen may diffuse into the steel and collect at high-stress locations such as inclusions and along grain boundaries.

Like fatigue, SSC is a complicated failure mechanism. Whether or not a component will fail depends on a variety of factors, only some having to do with the metal in the piece. Some metals are “immune” to SSC, but very few drill string materials are totally immune to SSC under all circumstances. The one generality that can be made, however, is that the greater the tensile strength of a steel the more susceptible it is to SSC.

Specialized tools are of particular concern in hydrogen sulphide service, as their designers need to cram a lot of gadgetry into limited space and still make a tool capable of carrying high loads. This means that material strength will often be
pushed to the limits, which in turn means that metal will also be highly susceptible to SSC.

- Controlling SSC, like controlling fatigue, is a matter of watching and suppressing as many as possible of the factors that work against us. The initiatives we can take to reduce the probability of SSC while drilling H₂S bearing formations can be divided into two categories.
  - Suppress the reaction between steel and H₂S
  - Use material that is less susceptible to SSC.
SECTION 7

TRIPPING

1. Tripping in

1) While tripping in, monitor the well on the trip tank and trip sheet with the trip tank pump running.

2) Tripping speeds into the hole should be determined from surge pressure calculations.

3) When tripping in after an extended period of downtime, circulate bottoms up at the casing shoe, and repeat at specified intervals to break gels, reduce filter cake build up, and flush gas accumulations.

4) When losses are a concern, consider washing down from the shoe to minimize mud gel effect. Wash at least the last stand to bottom.

5) If using a float valve, ensure valve is allowing drill string to fill. If not, then fill the pipe every 10 to 20 stands while running into the hole.

6) Always gauge bits and stabilizers before and after each trip. Ensure that the correct gauge ring is used for bits, some PDC bits need special rings.

7) When running a BHA of increased stiffness, expect to have to ream. Do not trip into the open hole rapidly.

8) If the hole is thought to be under gauged, extreme caution must be applied when tripping into the hole.

9) Rotate drill pipe before starting circulation to break gels and minimize pump surges. Slowly bring pumps up to speed.

2. Tripping out

To trip out of the hole without causing excessive swabbing, getting stuck, or taking a kick, consider the following:

- Circulate hole dean before tripping out; 2 to 4 times normal bottoms-up may be required; continue until shakers are clean.

- Flow check shall be conducted.
  - At hole TD, prior start POH.
  - When BHA is inside casing shoe.
  - Every 3000 ft.
  - Prior to pulling the BHA through BOP stack.
  - If the hole didn’t take the proper metal displacement.
• Consider pumping a sweep to determine if additional circulation time is necessary.
• Determine an overpull limit prior to pulling out of the hole (1/2 BHA weight, or 30,000 lbs whichever is less).
• Pull out of the hole at a speed that avoids swabbing (run surge/swab software).
• If overpull limit is reached, run in 1 stand, repeat hole cleaning procedure, and pull out of hole again. Repeat cycle if overpull limit is again reached.
• Before pulling out of the hole:
  • Monitor well with trip tank and trip sheet during trip. Flow check if any discrepancy occurs. Shut in immediately if any flow is observed.

3. Making Connections

Correct procedures when making connections protect the bit, optimize borehole quality and reduce the probability of inducing lost circulation, lateral vibrations, bit whirl, and thermal shock damage to PDC cutters.

The following guidelines should be used to minimize potential problems during connections.

• Wipe the last joint prior to making a connection (every joint with kelly). If erratic or high torque is experienced prior to the connection, take time to ensure the cuttings are well above the BHA.
• Be aware of warning signs indicating possible trouble. Common warning signs are increased drag (10-15,000 lbs above normal) when pulling bit off bottom and 200-300 psi increase in pump back pressure immediately after a making the connection. The best action is to work pipe up and down to circulate any cuttings above BHA before making the connection.
• Ream kelly down before making a connection if the hole continues to be tight. Ream and circulate until hole drag returns to normal.
• Connections should only be made if the hole condition is good. Never make a connection with any overpull onto the slips.
• After making a connection, break gels by rotating pipe in increments, then break circulation slowly, checking for returns at the shakers. Slowly bring pumps up to speed.
• Avoid starting and stopping the mud pumps suddenly. This may disturb the wellbore downhole (shock loading effect).
• Minimize the period without circulation during a connection.
Re-starting the bit:

• Bring mud pumps up to desired stroke rates slowly.

• Wait 10 seconds after reaching desired flow rate before starting rotary. Set the rotary speed to 60-80 rpm, or to half the target on-bottom value if the target rotary speed is lower than 120 rpm.

• Run the bit slowly back to bottom, keeping below 10 m/min at all times. Slowly increase the weight to the target value. Increase the rotary speed to the intended value.

• Optimize parameters within the specified range to achieve maximum penetration rate. Monitor surface torque fluctuations (or torsional vibration levels if a vibration monitoring system is in use) to determine if stick-slip motion of the string initiates as the weight is increased. If stick-slip motion is initiated, do not increase the weight further. Follow the procedures given for avoiding stick-slip vibration.

4. Reaming and Backreaming

Reaming (and backreaming) is a high risk operation which accounts for a large proportion of stuck pipe incidents. If reaming (and backreaming) operations are conducted too fast, solids from wash-outs and cavings are introduced into the circulating system at a faster rate than the hole is being cleaned. This results in a pack-off.

• Always pre-plan a trip. Know where high doglegs exist and note troublesome areas from past trips.

• Only backream as a last resort in all wellbore geometry’s.

• If the hole cannot be pulled and pulled/pumped out of (e.g. ledge, fault, tight hole, excessive drag, reactive, geo-pressured, mobile formation), only then should one attempt to temporarily rotate out (i.e. backream) through the restricted zone. Even then, extreme care and caution should be exercised at all times when executing such practice.

• Backreaming will (especially in pressure transition zones and/or highly drillable formations), cause hole enlargement, stresses the wellbore, and because it generates new cuttings, has a greater risk of causing pack-offs.

• Have singles in the V-door in case downward motion is required to free the pipe after a connection.

• The shakers must be monitored continuously and the volume of solids being removed from the wellbore should be noted. Large volumes of settled cuttings or new cavings can be introduced to the hole when reaming. It is critical that this material is circulated out of the hole.
• Use consistent parameters for reaming operations. This assists in identification of changes in torque and pressure trends.

• An increase in drag, torque or pressure may indicate that the annulus is loaded up, and a pack-off may be forming. Circulate and clean the wellbore before continuing reaming.

• If indications of a pack-off occur, immediately reduce the pump strokes (e.g. by half) to reduce the pistoning effect. If, after several minutes the hole does not pack-off, return to the original parameters and be prepared to circulate the hole clean.

• Prior to heavy reaming, slow rotation (< 80 rpm) should be used in an attempt to "walk" the pipe past ledges.

• The preferred practice is to always try to work the string past a tight spot as a first option. However, overpull limits must be known and used. Work up to the overpull limit in stages ensuring free movement in the other direction at each stage.

• Limiting overpulls to half the BHA weight has proven to be a successful strategy in avoiding stuck pipe.

• Reaming operations should be conducted with the same flow rate as drilling.

• Reaming weight and speed should be kept low if possible (< 10-15k lbs either up or down). This reduces the chance of sidetracking the well and is less damaging to the drill string.

• Control the speed of reaming operations (4 stands an hour can be used as a rule of thumb for the maximum speed). This should also reduce the mechanical damage the drill string does to the wellbore.

• Make sure the pipe is free before setting the slips.

• After drilling or reaming down, the cuttings should be circulated above the BHA prior to picking up.

• If when using a top drive, it stalls out during reaming operations there is a great deal of stored energy in the torqued up drill string. Always release this torque slowly.

• When back-reaming with a top-drive, do not overpull the pipe into the slips to connect the top drive.

• When washing in, with a motor in the BHA, rotate the whole drillstring at low rpm.
SECTION 8

DRILLING WITH PDC BITS

A PDC bit is much more fragile than a roller cone bit. It is 5 x more expensive and must be treated with maximum care.

The following practices are to be followed whenever using bent housing motors with PDC bits in order to minimize bit damage. Also in reference to windows running RSS through will need a bigger window to be cut.

- Down hole tools are to be tested at surface with used rock bit.
- Avoid testing down hole tools while run in hole (inside casing). If such testing is mandatory, minimum GPM is to be used.
- Moderate RPM and GPM are to be used while washing down prior drilling shoe track.
- Inspection of mills after opening window (in case of side track) is required prior RIH with PDC bit in order to ensure window accessibility and clear path.
- Precautions are to be taken while passing window with PDC bit. If the bit could not pass easily through the window, POH and RIH with clean out assembly to check the window accessibility.
- Attendance of bit running is mandatory in all cases.

1. General Recommendation for Drilling with PDC Bits

Prior to start drilling with PDC, hole must be free of junk (no dies, no Inserts from previous bit, no bolts, no pieces of metal). If any junk is suspected, Rig Manager and DS must be immediately informed.

1.1 Drilling Out

Drilling cement, float collar and float shoe as well as just below the shoe in the rat hole is very risky for all PDC bits.

- WOB: Max ¼ of maximum WOB (e.g. 10,000 lbs in 12 ¼”) especially with a bent housing.
- RPM: Maximum 50.
- GPM: Minimum for the PDM (e.g. 600 - 700 GPM in 12 ¼”).
- In float collar pick off bottom regularly to remove debris from the bit.
- Control ROP in the cement near F/C and F/S at 25 ft/hr.
If high torque is faced while tagging cement, it is likely that junk has been dropped in the hole. POOH to check or do not expect a good performance.

1.2 Running in Open Hole:

Reaming is not recommended with PDC. Extensive reaming is forbidden. WOB max 1/15 of maximum WOB (e.g. 3,000 lbs in 12 ¼") because only the gauge cutters are taking all the WOB. Monitor differential pressure of the mud motor at low values.

Wash to bottom the last 2 joints. Circulate ½ ft off bottom for 5 minutes with maximum GPM before starting making the bit pattern.

1.3 Make Bit Pattern (for 3 to 5 ft):

- WOB: 2,000 lbs to 3,000 lbs.
- RPM: Maximum 60.
- GPM: Maximum for motor.
- After 3 ft to 5 ft, gradually increase WOB to the optimum value.

1.4 Drilling the Formation:

- Never exceed the maximum WOB recommended by the bit manufacturer
- Limit the RPM to 50 until the stabilizers and roller reamers are in the open hole. Vibrations could occur when they are rotating in the float collar and/or float shoe.
- Regularly perform drill off tests to optimize the ROP.
- Drill at 80% of the max differential pressure of the mud motor.
- Do not accept any type of vibrations, bit bouncing or torque fluctuations are detrimental to ROP and bit life. Stop rotation and pick up until vibration has disappeared, then resume rotation. Adjust the RPM and WOB until the vibrations disappear. In some cases of bit whirl, lower RPM and higher WOB might reduce the bit vibration.
- Control the ROP (WOB kept at maximum ½ the max WOB: e.g. 20,000 lbs in 12 ¾") in ratty formations like the RUS or if a hard streak is planned.

1.5 Connections

Connection time must be minimized to get a good performance but a PDC bit must tag bottom very slowly. Hitting hard the bottom is breaking cutters and "kills" the bit.
MUD GUIDELINES

Revision-0
March 2005
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SECTION 1

HSE PRACTICES

1. Safe Handling of Chemicals

1.1 Chemicals Hazards

- The chemicals can present the following hazards:
  - Physical
  - Explosive
  - Oxidizing
  - Flammable
  - Biological
  - Toxicity
  - Harmful
  - Corrosive
  - Irritant
  - Poison (Gas)
  - Carcinogenic / mutagenic / teratogenic
  - Environmental hazards

- For the drilling fluids, cement and stimulation chemicals, the possible hazards are generally:
  - Flammable
  - Toxicity
  - Harmful
  - Corrosive
  - Irritant

- Chemicals presenting biological hazards can affect people when:
  - Inhaled (dust or vapor): They can affect the upper respiratory system, lungs, brain, liver, kidneys or bladder.
  - Contacting the skin: Toxic and harmful chemicals can enter the body through any opening of the skin (cut, sore).
  - Corrosive and irritant chemicals can cause burns, blister, rash or sore.
  - Swallowed: Ingestion usually occurs because of eating, drinking or smoking with contaminated hands or utensils.
1.2 Protective Measures

1.2.1 Fundamental Rules

- Before handling any chemical be aware of the hazards (in doubt, check with mud engineer/cement operator).

- Wear the required protective equipment (gloves, goggles, dust mask…)

- When handling chemicals do not eat or smoke. After handling chemicals, hands must be washed with soap and water before eating or smoking.

- Avoid all unnecessary personnel contact with chemicals. In case of contact, affected areas must be thoroughly washed with soap and water.

- When handling powder chemicals, wear dust mask.

- Containers must be kept closed when not in use.

- Spilled materials must be cleaned up immediately.

1.2.2 Protective Equipment

- Gloves (to avoid chemicals contacting the hands).

- Leather or cotton gloves: general use for powder chemicals (non corrosive).

- Rubber (or other synthetic material) gloves: to be used for liquid and/or corrosive chemicals.

- Splash goggles (to prevent chemicals to reach the eyes): to be used when handling corrosive and irritant chemicals.

- Face shield (to protect all the face): to be used when handling liquid and/or corrosive chemicals.

- Apron (to protect the body from splashes): to be used whenever handling corrosive chemicals are handled.
1.2.3 Do’s and Don’ts of Occupational Skin Care

Table 5-1: Occupational skin care guidelines

<table>
<thead>
<tr>
<th>DO’S</th>
<th>DON'TS</th>
</tr>
</thead>
<tbody>
<tr>
<td>• DO wear the correct protective clothing</td>
<td>• DO NOT wear dirty or oily protective clothing</td>
</tr>
<tr>
<td>• DO Use protective creams if you have to work without gloves.</td>
<td>• DO NOT use more pre-work cream than is necessary (if possible use a dispensing system)</td>
</tr>
<tr>
<td>• DO clean your skin with the correct cleanser at the end of each day and before breaks.</td>
<td>• DO NOT use a stronger cleanser than required</td>
</tr>
<tr>
<td>• DO pay attention to thumbs, fingertips and in between the fingers.</td>
<td>• DO NOT use substitutes for proper skin cleansers e.g. base fluid or solvents.</td>
</tr>
<tr>
<td>• DO dry your hands well with a clean towel</td>
<td>• DO NOT forget to wash your skin regularly.</td>
</tr>
<tr>
<td>• DO use a reconditioning cream as required</td>
<td>• DO NOT use dirty towels to dry your skin</td>
</tr>
<tr>
<td>• DO look after your skin</td>
<td>• DO NOT assume skin irritation will disappear, get prompt medical attention</td>
</tr>
</tbody>
</table>

1.3 Brine Handling

1.3.1 Specificity of brines

- Brine is simply a salt or a blend of salts in water. Most commonly used salts are: sodium chloride (NaCl), calcium chloride (CaCl₂) and calcium bromide (CaBr₂).

- Heavy brines will (due to their high salt content), absorb water from their surroundings. For instance, they will draw moisture out of leather boots causing severe shrinkage. Heavy brines will also absorb water from the SKIN and quickly cause pain if not washed off immediately.

1.3.2 Brines hazards

- Irritant to the skin

- As a general rule, brines become more irritating to the skin as their weight is increased and/or their pH becomes more acidic.
• NaCl brines are only slightly irritating to the skin. With prolonged exposure, CaCl₂ and CaBr₂ can be irritating to the skin.

• CaCl₂ and CaBr₂ should be washed off using soap and water no longer than 10 minutes after contact.

• Contaminated clothing should be removed.

• Heavy brines will immediately irritate the eyes, mucous membranes and any exposed cuts or scratches.

• The possibility of permanent damage increases with the length of exposure time. Immediately wash the affected area with plenty of water for a minimum of 15 minutes. Get qualified medical attention.

1.3.3 Protective equipment

• Splash goggles which seal around the eyes and protect from splashing at almost any angle. Glasses, safety goggles or even face shield only protect from head-on direction.

• Rubber (or plastic) gloves will protect the hands. Do not use leather gloves as they will soak up brines, shrink with time and offer little or no protection.

• Creams (containing lanolin and/or glycerin) will help prevent loss of moisture when used beforehand and help replace the oils and moisture already lost. To be only used in conjunction with gloves.

• Steel toe rubber boots should be worn instead of leather boots.

• Apron (rubber or plastic) should be worn when handling sacks.

• Dust mask to be worn when mixing finely ground materials.

1.3.4 Safety Equipment

• Eye wash fountains should be installed next to each area of high activity (rig floor, shale shakers, mixing hoppers, mud pits, cement unit...). They need to be kept cool in hot weather.

1.4 How to Avoid Exposure to Hazardous Chemicals or Risk

• Read the MSDS sheet so you understand the hazards.
• Handle in the manner recommended by the manufacturer on the MSDS.

• Make sure safety equipment is present and in working order.

• Make sure you have been fit tested for individual safety equipment, such as masks, respirators, etc.

• Wear recommended safety equipment when appropriate.

• Avoid horse play or other inappropriate activity.

• Avoid mixing chemicals over mud tanks.
SECTION 2

ADCO STANDARD MUD PROGRAM

1. Low Solid Non-Dispersed Mud (LSND)

1.1 Preparation

LSND mud preparation is depending on the mix water salinity.

1) If the salinity of make-up water is less than 8,000 ppm, mix spud mud as follows:

Table 5-2: LSND mud preparation if mix water salinity < 8000 ppm

<table>
<thead>
<tr>
<th>Typical Products</th>
<th>Primary Functions</th>
<th>Concentration ( ppb )</th>
</tr>
</thead>
<tbody>
<tr>
<td>BARITE</td>
<td>Increase density</td>
<td>As Required</td>
</tr>
<tr>
<td>Bentonite</td>
<td>Viscosity and fluid loss</td>
<td>20 - 25</td>
</tr>
<tr>
<td>Caustic Soda</td>
<td>pH and Pf</td>
<td>0.25 - 0.5</td>
</tr>
<tr>
<td>Soda ash</td>
<td>Control hardness</td>
<td>0.5 - 0.75</td>
</tr>
<tr>
<td>Lime</td>
<td>pH and Pm</td>
<td>1.0 - 2.0</td>
</tr>
</tbody>
</table>

2) If the salinity of make-up water exceeds 8,000 ppm, mix spud mud as follows:

Table 5-3: LSND mud preparation if mix water salinity > 8000 ppm

<table>
<thead>
<tr>
<th>Typical Products</th>
<th>Primary Functions</th>
<th>Concentration ( ppb )</th>
</tr>
</thead>
<tbody>
<tr>
<td>BARITE</td>
<td>Increase density</td>
<td>As Required</td>
</tr>
<tr>
<td>Salt Gel (Attapulgite)</td>
<td>Viscosity</td>
<td>20 - 25</td>
</tr>
<tr>
<td>Caustic Soda</td>
<td>pH and Pf</td>
<td>0.25 - 0.5</td>
</tr>
<tr>
<td>Lime</td>
<td>pH and Pm</td>
<td>1.0 - 2.0</td>
</tr>
</tbody>
</table>

Note: Flush the hole with 50 bbls high viscous pill, (120-150 sec/qt) periodically.

1.2 Mud Properties

Table 5-4: LSND mud properties

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

* For mud weight see the original well program.
1.3 Minimum Materials Required

Table 5-5: Minimum materials required on-site for LSND mud

<table>
<thead>
<tr>
<th>Products</th>
<th>Stock</th>
</tr>
</thead>
<tbody>
<tr>
<td>BARITE</td>
<td>30,000 Kgs</td>
</tr>
<tr>
<td>Bentonite</td>
<td>20,000 Kgs</td>
</tr>
<tr>
<td>Caustic Soda</td>
<td>1,200 Kgs</td>
</tr>
<tr>
<td>Soda ash</td>
<td>1,000 Kgs</td>
</tr>
<tr>
<td>Calcium chloride</td>
<td>1,000 Kgs</td>
</tr>
<tr>
<td>Lime</td>
<td>1,000 Kgs</td>
</tr>
</tbody>
</table>

2. Low Solid Non-Dispersed Polymer Mud

2.1 Preparation

This type of Mud should be prepared as following.

Table 5-6: Low Solid Non-Dispersed Polymer mud preparation

<table>
<thead>
<tr>
<th>Typical Products</th>
<th>Primary Functions</th>
<th>Concentration (ppb)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Salt</td>
<td>Increase density</td>
<td>As Required</td>
</tr>
<tr>
<td>XC Polymer</td>
<td>Viscosity</td>
<td>1.5 - 2.5</td>
</tr>
<tr>
<td>Caustic Soda or MgO</td>
<td>pH and Pf</td>
<td>0.25 - 0.5</td>
</tr>
<tr>
<td>Modified Starch</td>
<td>Fluid Loss Control</td>
<td>4.0</td>
</tr>
<tr>
<td>CaCO₃ fine</td>
<td>Mud Cake and Mud Weight</td>
<td>As Required</td>
</tr>
</tbody>
</table>

Note: For any dilution, the above concentration should be maintained.

2.2 Mud Properties

The following table shows the mud properties required to drill with this type of Mud.

Table 5-7: Low Solid Non-Dispersed Polymer mud properties

<table>
<thead>
<tr>
<th>Density*, pcf</th>
<th>Viscosity, sec/qt</th>
<th>YP, #/100 ft²</th>
<th>PV, cps</th>
<th>10 sec Gel , #/100 ft²</th>
<th>10 min Gel , #/100 ft²</th>
<th>API FL, cc/30 min.</th>
<th>Drill Solids Content, %</th>
<th>PH</th>
</tr>
</thead>
<tbody>
<tr>
<td>Density*</td>
<td>As Per Original Program</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Viscosity, sec/qt</td>
<td>45 – 55</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>YP, #/100 ft²</td>
<td>18 – 25</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PV, cps</td>
<td>ALAP/7 – 10</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>10 sec Gel , #/100 ft²</td>
<td>3 – 6</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>10 min Gel , #/100 ft²</td>
<td>8 – 12</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>API FL, cc/30 min.</td>
<td>6 - 8</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Drill Solids Content, %</td>
<td>&lt; 6 (max.) LGS</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PH</td>
<td>9.0 - 9.5</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

* For mud weight see the original well program.
2.3 Minimum Materials Required

Table 5-8: Minimum materials required on-site for Low Solid Non-Dispersed Polymer mud

<table>
<thead>
<tr>
<th>Products</th>
<th>Stock</th>
</tr>
</thead>
<tbody>
<tr>
<td>Salt</td>
<td>50,000 Kgs</td>
</tr>
<tr>
<td>XC-Polymer</td>
<td>10,000 Kgs</td>
</tr>
<tr>
<td>Caustic Soda</td>
<td>1,000 Kgs</td>
</tr>
<tr>
<td>Soda ash</td>
<td>1,000 Kgs</td>
</tr>
<tr>
<td>Modified Starch</td>
<td>10,000 Kgs</td>
</tr>
<tr>
<td>Defoamer</td>
<td>4 Drums</td>
</tr>
<tr>
<td>CaCO₃ fine</td>
<td>15,000 Kgs</td>
</tr>
</tbody>
</table>

Note: Do not increase PH more than 9.5 in case of high Calcium content.

3. KCL/XC-Polymer Mud

This type of mud is used to drill clay formation and prevent bit balling.

3.1 Preparation

Table 5-9: KCL/XC Polymer mud preparation

<table>
<thead>
<tr>
<th>Typical Products</th>
<th>Primary Functions</th>
<th>Concentration (ppb)</th>
</tr>
</thead>
<tbody>
<tr>
<td>KCL</td>
<td>Increase density and inhibition</td>
<td>30 - 38</td>
</tr>
<tr>
<td>XC Polymer</td>
<td>Viscosity</td>
<td>1.5 - 2.5</td>
</tr>
<tr>
<td>KOH</td>
<td>pH and Pf</td>
<td>0.25 - 0.5</td>
</tr>
<tr>
<td>Modified Starch</td>
<td>Fluid Loss Control</td>
<td>6.0 – 8.0</td>
</tr>
<tr>
<td>Lubricant</td>
<td>Lubricity</td>
<td>1%</td>
</tr>
</tbody>
</table>

3.2 Mud Properties

Table 5-10: 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               |

3.3 Minimum Materials Required

Table 5-11: Minimum materials required on-site for KCL/XC Polymer mud

<table>
<thead>
<tr>
<th>Products</th>
<th>Stock</th>
</tr>
</thead>
<tbody>
<tr>
<td>KCL</td>
<td>80,000 Kgs</td>
</tr>
<tr>
<td>XC-Polymer</td>
<td>10,000 Kgs</td>
</tr>
<tr>
<td>KOH</td>
<td>2,000 Kgs</td>
</tr>
<tr>
<td>Soda ash</td>
<td>1,000 Kgs</td>
</tr>
<tr>
<td>Modified Starch</td>
<td>10,000 Kgs</td>
</tr>
<tr>
<td>Defoamer</td>
<td>4 Drums</td>
</tr>
<tr>
<td>Lubricant</td>
<td>24 Drums</td>
</tr>
</tbody>
</table>
4. Aerated Mud

Location Water Gel based mud system is capable of tolerating a high solids content, display good thermal and rheological stability, and have excellent filter cake quality.

4.1 Additives

Table 5-12: Aerated mud additives

<table>
<thead>
<tr>
<th>Typical Products</th>
<th>Primary Functions</th>
<th>Concentration ( ppb )</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bentonite and/or Saltgel</td>
<td>Viscosity Control</td>
<td>20 - 25</td>
</tr>
<tr>
<td>Caustic Soda</td>
<td>pH and Pf</td>
<td>0.25 - 0.5</td>
</tr>
<tr>
<td>Modified Starch</td>
<td>Fluid Loss Control</td>
<td>4</td>
</tr>
<tr>
<td>Lime</td>
<td>pH and Pm</td>
<td>2.0</td>
</tr>
</tbody>
</table>

4.2 Mud Properties

Table 5-13: Aerated mud properties

<table>
<thead>
<tr>
<th>Density, pcf</th>
<th>Viscosity, sec/qt</th>
<th>YP, #/100 ft²</th>
<th>PV, cps</th>
<th>10 sec Gel, #/100 ft²</th>
<th>10 min Gel, #/100 ft²</th>
<th>API FL, cc/30 min.</th>
<th>Drill Solids Content, %</th>
<th>Sand, % by Volume</th>
<th>PH</th>
<th>MBT, ppb</th>
</tr>
</thead>
<tbody>
<tr>
<td>58 – 60</td>
<td>40 – 50</td>
<td>16 – 20</td>
<td>ALAP / 7 – 10</td>
<td>3 – 6</td>
<td>8 – 12</td>
<td>N/C to 15 – 20 prior to running CSG</td>
<td>&lt; 6 (max.) LGS</td>
<td>Traces – 0.5 (Max.)</td>
<td>11.0 – 12.5</td>
<td>20 – 25</td>
</tr>
</tbody>
</table>

4.3 Recommendations

- Pump 50 bbl of high viscous sweeps on connections.
- Increase volume and/or frequency of pills if any tight hole is noticed while connections.

4.4 Corrosion

- Corrosion Inhibitor is Sodium Silicate.
- Sodium Silicate is to be used to coat all DP's.
- Pump high viscous/high concentrate sodium silicate pills periodically while drilling with aerated Mud.
4.5 Guidelines

- Losses and flow are anticipated while drilling Dammam, UER and Simsima formations; however, injecting air while drilling these formations is only to reduce hydrostatic pressure in order to eliminate losses and to improve rate of penetration.

- Priority should be given to higher mud flow rate to achieve the required annular velocity and bit hydraulics.

- Pumping of maximum GPM mud should be maintained whenever possible, however, at deeper depths, surface pressure might exceed the air compression equipment capability which is 3000 psi. In this case mud flow rate should be reduced to have the surface pressure within the air package limitations.

- To evaluate the effect of hydrostatic pressure reduction on improving rate of penetration, choose a relatively hard section and drill without air, maintaining other drilling parameters. Continue drilling with enough amount of air to achieve negative differential pressure between 100 psi to 300 psi.

- Increasing the penetration rate causes minor increase 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.

- When Kelly is drilled down, slugging string should take a minimum amount of time. Before every connection bleed off the Kelly and by pass the air injection.

- Make check trip as necessary 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 flow line, remove rotating head insert after pulling at least 10 stands.
5. Salt Saturated / Polymer

5.1 Preparation

Table 5-14: Salt Saturated / Polymer mud preparation

<table>
<thead>
<tr>
<th>Typical Products</th>
<th>Primary Functions</th>
<th>Concentration (ppb)</th>
</tr>
</thead>
<tbody>
<tr>
<td>BARITE</td>
<td>Increase density</td>
<td>As Required</td>
</tr>
<tr>
<td>Salt</td>
<td>Weight / Inhibition</td>
<td>To Saturate the Water</td>
</tr>
<tr>
<td>XC-Polymer</td>
<td>Viscosifier</td>
<td>1.5 – 2.0</td>
</tr>
<tr>
<td>C.Soda and / or MgO</td>
<td>pH and Pf</td>
<td>0.75 – 1.0</td>
</tr>
<tr>
<td>Modified Starch</td>
<td>Fluid Loss Control</td>
<td>6.0 – 8.0</td>
</tr>
<tr>
<td>Zinc Carbonate</td>
<td>H2S Scavenger</td>
<td>2.0</td>
</tr>
<tr>
<td>CaCO3</td>
<td>Bridging Agent</td>
<td>10.0 – 12.0</td>
</tr>
</tbody>
</table>

5.2 Mud Properties

Table 5-15: Salt Saturated / Polymer mud properties

<table>
<thead>
<tr>
<th>Density, pcf</th>
<th>75 - 78 or as hole conditions dictates</th>
</tr>
</thead>
<tbody>
<tr>
<td>Viscosity, sec/qt</td>
<td>45 – 55</td>
</tr>
<tr>
<td>YP, #/100 ft²</td>
<td>20 – 25</td>
</tr>
<tr>
<td>PV, cps</td>
<td>10 – 15</td>
</tr>
<tr>
<td>10 sec Gel, #/100 ft²</td>
<td>3 – 6</td>
</tr>
<tr>
<td>10 min Gel, #/100 ft²</td>
<td>8 – 12</td>
</tr>
<tr>
<td>API FL, cc/30 min.</td>
<td>&lt; 5</td>
</tr>
<tr>
<td>Drill Solids Content, %</td>
<td>&lt; 6 (max.) LGS</td>
</tr>
<tr>
<td>Sand, % by Volume</td>
<td>Traces – 0.5 (Max.)</td>
</tr>
<tr>
<td>PH</td>
<td>9.0 – 9.5</td>
</tr>
<tr>
<td>Chlorides , ppm</td>
<td>&gt; 150,000</td>
</tr>
</tbody>
</table>

6. Non-Damaging Fluid

6.1 Mixing and Preparation

- Every tank and line to be used with this type of fluid must be thoroughly cleaned and washed. All solids and chemicals should be carefully removed prior to mixing to reduce contamination and solids content.
- To facilitate operations keep a minimum volume available in the active system to be used to drill out cement (either old mud or location water).
- The basic formulation should be as follows for one final barrel:

Table 5-16: Non-Damaging Fluid preparation

<table>
<thead>
<tr>
<th>Typical Products</th>
<th>Primary Functions</th>
<th>Concentration (ppb)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Salt</td>
<td>Weight / Inhibition</td>
<td>To Saturate the Water</td>
</tr>
<tr>
<td>XC-Polymer</td>
<td>Viscosifier</td>
<td>1.5 – 2.0</td>
</tr>
<tr>
<td>C.Soda and / or MgO</td>
<td>pH and Pf</td>
<td>0.75 – 1.0</td>
</tr>
<tr>
<td>Modified Starch</td>
<td>Fluid Loss Control</td>
<td>6.0 – 8.0</td>
</tr>
<tr>
<td>Calcium Carbonate</td>
<td>Bridging agent / Weight</td>
<td>12 - 20</td>
</tr>
<tr>
<td>Zinc Carbonate</td>
<td>H2S Scavenger</td>
<td>2.0</td>
</tr>
</tbody>
</table>
Note: Mud weight should be increased by using Calcium Carbonate fine

- Order of addition of products:
  It is imperative that the order of addition products given hereunder be respected, otherwise severe foaming problems will be encountered.
  - Water
  - Common Salt (NaCl)
  - Defoamer
  - XC Polymer
  - Sodium Hydroxide and/or MgO
  - Calcium Carbonate Fine
  - H₂S Scavenger (Zinc Carbonate where it is required)

6.2 Displacement of the Hole to Non-Damaging Fluid

- Prepare and store enough volume in order to carry on drilling without delay after displacement of the non-damaging fluid to the hole. Drill out cement and float equipment preferably with old mud to 10 ft above shoe.
- Displace hole to non-damaging fluid at a high circulation rate while slowly rotating the pipe.
- If cement is drilled out with location water do not use any spacer while displacing hole with non-damaging fluid.
- If cement was drilled out with the old mud use a spacer of 100 bbls ahead of non-damaging fluid.

6.3 Mud Properties

Table 5-17: Non-Damaging Fluid properties

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Density*, pcf</td>
<td>68 – 72 or as hole conditions dictates</td>
</tr>
<tr>
<td>Viscosity, sec/qt</td>
<td>40 - 50</td>
</tr>
<tr>
<td>YP, #/100 ft²</td>
<td>20 – 25</td>
</tr>
<tr>
<td>PV, cps</td>
<td>ALAP / 10 – 15</td>
</tr>
<tr>
<td>10 sec Gel , #/100 ft²</td>
<td>3 - 5</td>
</tr>
<tr>
<td>10 min Gel , #/100 ft²</td>
<td>10 - 16</td>
</tr>
<tr>
<td>API FL, cc/30 min.</td>
<td>3 - 4</td>
</tr>
<tr>
<td>Drill Solids Content, %</td>
<td>&lt; 6 (max.) LGS</td>
</tr>
<tr>
<td>PH</td>
<td>8.5 - 9.0</td>
</tr>
<tr>
<td>Chlorides , ppm</td>
<td>120,000</td>
</tr>
</tbody>
</table>

* Mud weight confirmation will be issued in the final well program.

6.4 Acid Soluble Pill Formulation if Losses are Encountered in Reservoir

- Have required volume of water
• Mix 3 - 5 USG Defoamer
• Mix 1.5 – 2.0 lbs/bbl XC Polymer (very slowly)
• Mix 50 - 60 lbs/bbl CaCO₃ (F)
• Mix 50 – 60 lbs/bbl CaCO₃ (M)
• Mix 80 - 150 lbs/bbl CaCO₃ (C)

CaCO₃ (F), (M) and (C) amount depends on losses rate.

Notes:
- Start pumping the pill while mixing the second half of CaCO₃ (C) amount to avoid settling.
- In case of complete losses increase the concentration of CaCO₃ (F), (M) and (C) to 150 lb/bbls, and use 120-150 bbls water.

6.5 Minimum Materials Required

Minimum quantities of products must be available on location before start mixing:

Table 5-18: Minimum materials required on-site for Non-Damaging Fluid

<table>
<thead>
<tr>
<th>Products</th>
<th>Stock</th>
</tr>
</thead>
<tbody>
<tr>
<td>Salt</td>
<td>80,000 Kgs</td>
</tr>
<tr>
<td>C. Soda and / Or MgO</td>
<td>3,000 Kgs</td>
</tr>
<tr>
<td>Zinc Carbonate</td>
<td>1,000 Kgs</td>
</tr>
<tr>
<td>Modified Starch</td>
<td>10,000 Kgs</td>
</tr>
<tr>
<td>Calcium Carbonate Fine</td>
<td>10,000 Kgs</td>
</tr>
<tr>
<td>Defoamer</td>
<td>4 Drums</td>
</tr>
<tr>
<td>BioPolymer ( XC-Polymer )</td>
<td>3,000 Kgs</td>
</tr>
</tbody>
</table>

7. Recommended Minimum Shale Shaker Screen Sizes

Table 5-19: Minimum shale shaker screen sizes

<table>
<thead>
<tr>
<th>Hole Section</th>
<th>Shaker # 1 (3 panels)</th>
<th>Shaker # 2 (3 panels)</th>
<th>Shaker # 3 (4 panels)</th>
</tr>
</thead>
<tbody>
<tr>
<td>26&quot;</td>
<td>3 X 100 mesh</td>
<td>3 X 100 mesh</td>
<td>4 X 125 mesh</td>
</tr>
<tr>
<td>17-1/2&quot;</td>
<td>3 X 100 mesh</td>
<td>3 X 100 mesh</td>
<td>4 X 125 mesh</td>
</tr>
<tr>
<td>12-1/4&quot;</td>
<td>3 X 125 mesh</td>
<td>3 X 125 mesh</td>
<td>4 X 140 mesh</td>
</tr>
<tr>
<td>8-1/2&quot;</td>
<td>3 X 200 mesh</td>
<td>3 X 200 mesh</td>
<td>4 X 230 mesh</td>
</tr>
<tr>
<td>6&quot;</td>
<td>3 X 200 mesh</td>
<td>3 X 200 mesh</td>
<td>4 X 230 mesh</td>
</tr>
</tbody>
</table>

Notes:
- The 3 shale shakers must be run together in parallel all the time. In 8 ½” and 6” section, running 2 units only may be acceptable (SS # 3 + one other) if total mudflow can be accommodate screens.
The above is the minimum sizes to be used, if the mud does not cover + 75% of the screens area, use finer screens.

In case of newly mixed mud, coarser screens (one size down) could be used temporarily, but recommended screens must be installed as soon as the mud is sheared.

In any case, the minimum screen size to be used is 80 mesh, there is absolutely no reason to use coarser than that with the type of equipment we have on the rig.

Screens and Rubbers must be in good shape at all time, they must be changed as soon as starting to worn out.

Pyramid screens are only recommended in the pond (flowline side), flat screens can be used on the last panel (discharge side), and doing so will produce dryer cuttings than with all the panels being Pyramid.

It is the responsibility of the mud engineer to ensure adequate screens stock (in size and quality) on the rig. Any shortage/problem to be reported straight away to FME/SME.

Optimized shaker setting shall be maintained for effective cutting removal.

In top hole, if need be, the cyclones can be used as standard desanders and desilters with the heavy effluent directly discarded to the waste pit (if dumping allowed).

8. Hi-G Dryer

8.1 Hi-G Dryer Used Without Centrifuge to Treat the Recovered Mud

The Hi-G dryer to be considered only as a mean of drying the cuttings and the recovered mud to be disposed-off the same way as the waste mud (injected into annulus or dumped if allowed).

8.2 Hi-G Dryer Used in Combination with a Centrifuge

The recovered mud to be recycled to the mud system only after going through the centrifuge at the highest speed in order to eliminate the maximum of solids.
SECTION 3

TROUBLE SHOOTING

1. Shale and Wellbore Stability

Wellbore instability is generally experienced while drilling through shale formation and in particular, when going through the Nahr Umr shales.

The shale stability is function of three main parameters, the level of inhibition provided by the mud (mud type), the hydrostatic pressure exerted by the fluid (mud weight) and the angle at which the formation is drilled (hole angle).

1.1 Mud Inhibition

Standard Water Based Mud penetrates the shale and destabilizes the formation either by hydration/swelling or by sloughing.

WBM inhibition relies either on salt (salt saturated or KCL) and/or on specific chemicals (PHPA, Glycol, Silicates, etc…). OBM are inhibitive by nature as only oil (and not water) is in direct contact with the formation.

The inhibition provided by different mud types is as follows (from maximum inhibition to minimum):

OBM > Silicates mud > KCL/PHPA/Glycol mud > Salt Saturated Polymer mud > Fresh water muds.

1.2 Mud Weight

Drilling through shales releases the overburden and tectonic stresses. As shales are plastic or brittle, this decreases their stability and leads to caving. Additional pressure exerted by increased mud weight will compensate for stress reduction and thus reduce shale instability.

1.3 Hole Angle

As the hole angle increases the shale stability decreases and better inhibition and higher mud weights are required to offset the instability and retain trouble free operations. Moreover, inhibition and MW are interrelated; drilling with a more inhibitive fluid (e.g. switching from KCl/PHPA to OBM) allows the use of a lower mud weight as usual and vise versa.

The following figure summarizes ADCO experience and present the recommended MW required to drill through the Nahr Umr Shales function of mud type and hole angle.
Figure 5-1: Recommended MW in Nahr Umr Shales vs Hole Angle (All Fields)

Recommended Mud Weight in Nahr Umr Shales vs Hole Angle (All Fields)

Recommended Mud Weight with KCl/PHPA mud

Recommended Mud Weight with Polymer mud

Recommended Mud Weight with OBM

MW (pcf)

Hole Angle

Recommended Mud Weight in Nahr Umr Shales vs Hole Angle (All Fields)
-UP DATED ON 01/01/2002 -
2. Lost Circulation

Good planning and proper drilling practices are the keys to prevent lost circulation and to minimize excessive pressures on formation.

2.1 Minimizing Downhole Pressure

- Pipe movement should not exceed critical speeds when tripping.
- Rapid movement of pipe while circulating also causes even greater pressure surges, rapid spudding of the pipe or fast reaming while circulating can create large surges.
- Very high ROP loads the annulus with cuttings, thus increases the ECD, it is important to circulate hole clean prior to making connection.
- Rapid starting or stopping of the pumps can cause pressure surges, rotating the pipe when starting circulation will aid breaking the gel strengths and greatly reduce the surge pressure, maintaining low gel strength and gradually increasing the pump rate will reduce the surge pressure.
- Wash and ream cautiously through bridges.
- Control mud properties in the proper range (high viscosity and gel strength increases surge pressure).
- Control drilling solids at the minimum practical level and add proper treatment to minimize filter-cake build up.
- Drill with minimum mud weight.
- A good selection of the proper size of bridging materials helps reduce and eliminate whole mud losses into porous formations.

2.2 Combating Losses

When lost circulation is first noted, the conditions at the time the loss occurred should be accurately recorded and studied. The time of the occurrence (while drilling, circulation or tripping), the type of the loss (seeping, partial or complete) and the severity of the loss 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.

2.3 Position of OEDP

The OEDP must be positioned with regard to losses

Partial losses 5 to 50 Bbls/hr. : OEDP 5 to 10 ft below thief zone
Partial losses 50 to 100 Bbls/hr : OEDP across thief zone
Partial losses 100 Bbls/hr to total losses : OEDP 50 to 100 ft above thief zone

2.4 Volume of the Plug

The volume to be spotted depends on the type of losses and the result obtained with the previous plug

Partial losses 50 to 100 Bbls/hr : 150 linear feet in the well
Partial losses 100 to 500 Bbls/hr : 300 to 1,000 linear feet in the well
Total losses : 1,000 linear feet minimum in the well

2.5 Displacement Rate

• Pump the pill fast till it enters the annulus, and then adjust the pumping rate.
  Mud losses < 300 Bbls/hr : 30% over flow rate of losses and 100 gpm minimum.
  Mud losses > 300 Bbls/hr : 50% over flow rate of losses and pump capacity as maximum
• Spot the plug to hydrostatic equilibrium in accordance with the density of fluids in the well and the vacuum in annulus.
• Monitor annulus while pumping plug.
• POOH up to theoretical top of plug and/or last casing shoe.
• Do not circulate to clean pipe if losses > 100 Bbls/hr.
• If the mud annulus level is on surface, try to perform a hesitation squeeze to a pressure below the frac formation pressure.
• If annulus is not full, wait about one hour and try to fill it up, if successful attempt to squeeze.
2.6 Recommended Plugs

1) LCM for top hole section:

Table 5-20: Recommended LCM plugs for top hole

<table>
<thead>
<tr>
<th>Materials</th>
<th>Plug # 1</th>
<th>Plug # 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Kwik Seal Fine</td>
<td>15 ppb</td>
<td>15 ppb</td>
</tr>
<tr>
<td>Kwik Seal Medium</td>
<td>15 ppb</td>
<td>20 ppb</td>
</tr>
<tr>
<td>Kwik Seal Coarse</td>
<td>20 ppb</td>
<td>20 ppb</td>
</tr>
<tr>
<td>Wall Nut Fine</td>
<td>15 ppb</td>
<td>15 ppb</td>
</tr>
<tr>
<td>Wall Nut Medium</td>
<td>15 ppb</td>
<td>20 ppb</td>
</tr>
<tr>
<td>Wall Nut Coarse</td>
<td>20 ppb</td>
<td>20 ppb</td>
</tr>
<tr>
<td><strong>Total LCM</strong></td>
<td><strong>80 ppb</strong></td>
<td><strong>110 ppb</strong></td>
</tr>
</tbody>
</table>

2) LCM for Carbonate reservoir:

Table 5-21: Recommended LCM plugs for carbonate reservoir

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<thead>
<tr>
<th>Materials</th>
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<th>Plug # 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>CaCO₃ Fine</td>
<td>50 ppb</td>
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</tr>
<tr>
<td>CaCO₃ Medium</td>
<td>30 ppb</td>
<td>50 ppb</td>
</tr>
<tr>
<td>CaCO₃ Coarse</td>
<td>20 ppb</td>
<td>30 ppb</td>
</tr>
<tr>
<td><strong>Total LCM</strong></td>
<td><strong>100 ppb</strong></td>
<td><strong>100 ppb</strong></td>
</tr>
</tbody>
</table>

3. Stuck Pipe

Stuck pipe is one of the more common and serious drilling problems. It can range in severity from minor inconvenience, which can increase costs slightly, to major complications, which can have significantly negative results.

If the pipe becomes stuck, every effort should be made to free it quickly. The probability to freeing stuck pipe successfully diminishes rapidly with time.

In general, pipe becomes stuck either mechanically or differentially.

3.1 Type of Pipe Sticking

- Mechanically stuck pipe

  Mechanical sticking is caused by a physical obstruction or restriction. It can be grouped into two major categories:

  i. Hole pack-off and bridges.
     - Settled cuttings
     - Shale instability
     - Unconsolidated formations
     - Cement or junk in the hole
  
  ii. Hole Geometry
3.2 Weighted Pipe Free Formulations (for 1 Bbl)

<table>
<thead>
<tr>
<th>Weight (pcf)</th>
<th>Diesel (bbl)</th>
<th>Water (bbl)</th>
<th>Pipe free (gal)</th>
<th>Barite (lbs)</th>
</tr>
</thead>
<tbody>
<tr>
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<td>0.612</td>
<td>0.204</td>
<td>6.5</td>
<td>42</td>
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<td>65</td>
<td>0.603</td>
<td>0.201</td>
<td>6.4</td>
<td>64</td>
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<td>68</td>
<td>0.593</td>
<td>0.198</td>
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<td>72</td>
<td>0.584</td>
<td>0.195</td>
<td>6.2</td>
<td>109</td>
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<td>75</td>
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<td>131</td>
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<td>0.526</td>
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<td>94</td>
<td>0.517</td>
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<td>97</td>
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<td>100</td>
<td>0.497</td>
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<td>103</td>
<td>0.488</td>
<td>0.163</td>
<td>5.2</td>
<td>332</td>
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</table>

3.3 Mixing Procedure

- Fill slug pit with the required amount of diesel.
- Add the Pipe free concentrate.
- Add the required amount of water and stir until water is thoroughly emulsified with oil.
Finally add barite until the desired weight is reached.
Keep mixing until ready to be displaced.

### 3.4 Spotting Procedure

- Mix enough volume of free pipe pill to fill the annulus opposite the BHA plus 20 bbls and at the same weight as the mud in hole.
- Displace the spotting fluid until the top of the BHA is covered.
- Work and torque pipe and every ½ hour, pump into the annulus 2 bbls of spotting fluid.
- If no progress is obtained after 12 hours, circulate the spotting fluid out of the hole.
SECTION 4

COMPLETION AND WORKOVER FLUIDS

Completion and workover fluids are specialized fluids used during well completion operations and remedial workover procedures.

1. Workover Fluids Purposes
   - Control subsurface pressure.
   - Minimize formation damage.
   - Maintain wellbore stability.
   - Transport solids.
   - Maintain stable fluid properties.

2. Types of Completion and Workover Fluids
   1) Clear, solids-free brines.
   2) Polymer-viscosified brines with bridging /weighting agents.

3. Mixing Procedure
   1) Clean the tank from any sludge.
   2) Fill the tank with the required water.
   3) Add defoamer as required.
   4) Mix the required salt.
   5) Keep the agitators running while mixing.
   6) Stop the agitators and measure the brine weight after ½ hrs.
   7) Add 2% corrosion inhibitor and 2.5 gal/100Bbls bactericide for completion fluids.

4. Displacement Procedure for Completion Fluids
   1) Filtration unit to be available on rig site during well completion.
2) Filter the brine used for injection as for completion.

3) Clean active tanks completely and transfer new fluid.

4) Plan PBTD at a minimum of 30 feet below the lowest perforation interval if possible taking into account special zone isolation and depth requirements in well prognosis.

5) Circulate to clean hole using 100 bbls low viscous pill followed by 100 bbls Hi-viscous pill with the maximum allowable pump pressure and rate to insure strong turbulent flow which will help removing solids and cleaning the hole.

6) Reciprocate and rotate drill string continuously to PBTD with 60-90 rpm.

7) Circulate until shale shaker are clean .Displace the hole with the filtered completion brine.

8) Land drill string at PBTD (vertical cased hole wells) and close pipe rams .Reverse circulate at maximum rate, take all fluid returns over to the reserve pit ,run the filtration unit then transfer to another pit ,continue reverse circulating until clean packer fluid is obtained on surface.

Notes:

- Special trip with open ended drill pipe should be considered.

- During reverse circulation, agitators, mud guns and centrifugal pumps are to remain TURNED OFF.

- If any reverse circulation takes place while running completion, the returned fluid should be re-filtered.
5. Brine Formulation

5.1 Sodium Chloride Brine Requirements Using 100% NaCl

Table 5-22: Formulation of Sodium Chloride Brine using 100% NaCl

<table>
<thead>
<tr>
<th>Brine Density at 70° F (lb/gal)</th>
<th>Brine Density at 70° F (PCF)</th>
<th>Water (bbl)</th>
<th>100% NaCl (lb)</th>
<th>Crystallization Point (°F)</th>
</tr>
</thead>
<tbody>
<tr>
<td>8.4</td>
<td>62.8</td>
<td>0.998</td>
<td>4</td>
<td>+31</td>
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<tr>
<td>8.5</td>
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<td>0.993</td>
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<tr>
<td>8.6</td>
<td>64.3</td>
<td>0.986</td>
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<td>8.9</td>
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</tr>
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<td>68.8</td>
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<td>9.4</td>
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<td>10.0</td>
<td>74.8</td>
<td>0.888</td>
<td>109</td>
<td>+25</td>
</tr>
</tbody>
</table>

5.2 Sodium Chloride Density, Specific Gravity and Composition

Table 5-23: Sodium Chloride Brine density, specific gravity and composition

<table>
<thead>
<tr>
<th>Brine Density at 70° F (ppg)</th>
<th>Brine Density at 70° F (PCF)</th>
<th>Specific Gravity</th>
<th>NaCl Weight (%)</th>
<th>Na Weight (%)</th>
<th>Cl Weight (%)</th>
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<tbody>
<tr>
<td>8.4</td>
<td>62.8</td>
<td>1.008</td>
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<td>8.5</td>
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<td>1.032</td>
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<td>12.36</td>
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</tr>
</tbody>
</table>

To calculate parts per million multiply the weight percent by 10,000.
### 5.3 Calcium Chloride Brine Requirements Using 94-97% CaCl₂

Table 5-24: Formulation of Calcium Chloride Brine using 94-97% CaCl₂

<table>
<thead>
<tr>
<th>Brine Density at 70° F (lb/gal)</th>
<th>Brine Density at 70° F (pcf)</th>
<th>To Make 1 bbs (42 gal)</th>
<th>94-97% CaCl₂ (lb)</th>
<th>Crystallization Point (°F)</th>
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</thead>
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5.4 Calcium Chloride Brine Density, Specific Gravity and Composition

Table 5-25: Calcium Chloride Brine density, specific gravity and composition

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<th>Brine Density at 70° F (ppg)</th>
<th>Brine Density at 70° F (Pcf)</th>
<th>Specific Gravity</th>
<th>CaCl₂ Weight (%)</th>
<th>Calcium Weight (%)</th>
<th>Chloride Weight (%)</th>
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<td>1.381</td>
<td>37.03</td>
<td>13.37</td>
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<td>37.89</td>
<td>13.68</td>
<td>24.21</td>
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</table>

(Details as per API – Specification 10 Appendix ‘C’).
CASING AND CEMENTING
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SECTION 1

CASING HANDLING, PREPARATION & RUNNING GUIDELINES

1. Introduction

This Section provides the reader with the best practices for handling, preparing and running casing strings. The material presented is a distillation of actual field experience and information gathered from different places. In addition, this Section contains technical data and information that is required for performing successful casing operations.

All DD personnel involved in designing, planning and running casing are advised to read this section and use it as a reference document.

2. Casing Handling and Preparations Guidelines

2.1 Handling

- Ensure that pipe racks are leveled and properly positioned to allow transfer of casing from the racks to the catwalk.
- Ensure that thread protectors are placed on all connections before loading or unloading casing.
- Avoid rough handling of casing which might damage in any fashion the pipe body or connections. Dents in the casing body can reduce collapse rating and lead to failure in service.
- Do not unload casing by dropping joints onto the racks. Maintain control of the casing at all times by handling a small number of joints.
- Do not place hooks in the ends of casing. Joints should be slung from spreaders, evenly spaced along the joints.
- When rolling casing on the racks, do not allow joints to strike each other.
- Always leave thread protectors in place when the casing is being moved.
- Casing should be placed on level tumble racks or clean metal or wooden surfaces, free of any debris.
2.2 Preparation and Inspection

2.2.1 On-Rack Preparations

- The rig crew should clean the connection threads (both pin and box) and the protectors with a high pressure steam jet, followed by an air blast to dry the item, to prevent thread and seal corrosion.

- Diesel or paraffin should not be used for thread cleaning since, if not fully removed, a lack of lubricant adhesion to thread / seal surfaces can result. Also, this type of medium does not effectively clean the thread (it has a tendency to smear). It also attracts foreign debris which can be encapsulated in the thread roots, resulting in galling on make-up.

- Cleaning and drying should be of a quality that will allow all features of the connection to be clearly visible.

- After the threads and protectors are completely dry and clean protectors should be re-installed. Failure to keep connections dry before installing protectors can lead to thread / seal corrosion due to entrapped water being held inside the pipe bore.

- If the casing is to be left for more than 10 days at the rig site, corrosion protective grease should be applied to the connections.

- Casing returned to Bab-13 has to be protected with storage grease and casing protectors.

- All casing and accessory equipment should be visually inspected before it is run in the hole. Where possible, the function of accessory pieces should be confirmed before assembly.

- Damaged or undersized joints should be marked with red paint and back loaded immediately. Record the reason for rejection on the loading note returning them to drilling warehouse.

- The cleaning, inspection, and tallying operations are repeated as each tier of casing is uncovered.

- If a mixed string is to be run (more than one grade and/or weight), ensure that sufficient pipe of the required type is available, and that it is laid out on the racks so that it will be accessible when called for in the program.

- The casing tally will be recorded on the proper form and will include all joints remaining on the rack. Tally numbers should be planned so the shoe joint will be joint No.1.
• All measurements should be made with steel tape (with no welds).

• With the thread protectors removed and the connections cleaned, tally the casing and accessory pieces by measuring the length from the face of the coupling to the point on the pin connection where the coupling stops when the connection is assembled power tight. The distance from the end of the pin nose to this point is referred to as the make-up loss. Alternately, the total length of the joint can be measured, and the make-up loss subtracted from the overall length. Tallies should be made to the nearest 0.01 ft.

2.2.2 Rig Floor Preparations

• The size and condition of all related handling equipment should be checked thoroughly, particularly, slips, elevators, back-up tongs, and power tongs.

  **Note:**

  Slip and tong marks or gouges are injurious, and can result in failure of the casing in service. Properly fitting and well maintained equipment can greatly reduce the chance of damaging the casing.

• Check that the blocks are centered over the rotary table. If not, make the crew aware that the misalignment can result in difficulty when stabbing and spinning up connections.

• Spider slips should be used for heavy casing strings or for critical service casing. Again, the dies must be clean and sharp, and all of the same size. Do not mix old or re-sharpened dies with new dies in either the slips or the elevators.

• Check the rigging of the power tongs, making sure that the tong back-up line is at right angles to the tongs, the tongs are level, are free to move and are at the correct height above the floor.

• Check the size and rating of the power tongs. The nominal size of the tongs should not be more than one size larger than the pipe being run (i.e. do not use 13 3/8" tongs to run 7" casing) and the tongs must be able to readily attain the maximum expected torque.

• Ensure that the power tongs are equipped with an accurate and reliable torque gauge either electronic or hydraulic.

• Check that the back-up tongs are level and do not interfere with the suspension or operation of the power tongs.
2.3 Equipment Checklist

Before start running casing string it is very important to check the required running equipment to make sure that all the required equipments are available and ready to use.

2.3.1 18 ¾” casing

Following is the equipment checklist for running 18 ¾” casing.

Table 6-1: Equipment checklist for running 18 ¾” casing

<table>
<thead>
<tr>
<th>Item</th>
<th>Quantity</th>
<th>Description</th>
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</thead>
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<tr>
<td>1</td>
<td>1</td>
<td>18 ¾” safety clamp</td>
</tr>
<tr>
<td>2</td>
<td>1</td>
<td>18 ¾” side door elevators</td>
</tr>
<tr>
<td>3</td>
<td>1</td>
<td>18 ¾” single joint elevators</td>
</tr>
<tr>
<td>4</td>
<td>1</td>
<td>18 ¾” hand slips</td>
</tr>
<tr>
<td>5</td>
<td>1 set</td>
<td>Casing tongs c/w necessary jaws</td>
</tr>
<tr>
<td>6</td>
<td>1</td>
<td>18 ¾” circulating swedge with Lo-torque valve</td>
</tr>
<tr>
<td>7</td>
<td>1</td>
<td>18 ¾” power tong</td>
</tr>
<tr>
<td>8</td>
<td>1</td>
<td>Power unit for tong</td>
</tr>
<tr>
<td>9</td>
<td>1</td>
<td>Casing spool running tool if required</td>
</tr>
<tr>
<td>10</td>
<td>1</td>
<td>18 ¾” landing joint</td>
</tr>
<tr>
<td>11</td>
<td>1</td>
<td>18 ¾” float shoe</td>
</tr>
<tr>
<td>12</td>
<td>1</td>
<td>18 ¾” float collar / or stab-in float collar</td>
</tr>
<tr>
<td>13</td>
<td>As required</td>
<td>18 ¾” centralizers</td>
</tr>
<tr>
<td>14</td>
<td>As required</td>
<td>Stop collars c/w spiral nails</td>
</tr>
<tr>
<td>15</td>
<td>As required</td>
<td>Centralizer nails</td>
</tr>
<tr>
<td>16</td>
<td>1 set</td>
<td>Split casing bushing for rotary table</td>
</tr>
<tr>
<td>17</td>
<td>1</td>
<td>18 ¾” casing drift</td>
</tr>
<tr>
<td>18</td>
<td>As required</td>
<td>Thread lock</td>
</tr>
<tr>
<td>19</td>
<td>As required</td>
<td>Casing dope (API)</td>
</tr>
<tr>
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<td>1</td>
<td>Cementing stinger sub (4½ IF box conn)</td>
</tr>
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<td>4</td>
<td>“O” rings for cementing stinger sub</td>
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<td>22</td>
<td>1</td>
<td>18 ¾”x5” spring bow centralizer</td>
</tr>
<tr>
<td>23</td>
<td>1</td>
<td>18 ¾” casing bowl for running cementing stinger</td>
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<tr>
<td>24</td>
<td>1 lot</td>
<td>Casing head housing equipment</td>
</tr>
<tr>
<td>25</td>
<td>1</td>
<td>18 ¾” wear bushing, if required</td>
</tr>
<tr>
<td>26</td>
<td>1</td>
<td>Wear bushing running tool, if required</td>
</tr>
<tr>
<td>27</td>
<td>1 set</td>
<td>Cementing darts</td>
</tr>
<tr>
<td>28</td>
<td>1</td>
<td>18 ¾” casing drift</td>
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2.3.2 13 ¾” casing

Following is the equipment checklist for running 13 ¾” casing.

**Table 6-2: Equipment checklist for running 13 ¾” casing**

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<th>Item</th>
<th>Quantity</th>
<th>Description</th>
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<td>13 ¾” side door elevators</td>
</tr>
<tr>
<td>2</td>
<td>1</td>
<td>13 ¾” single door elevators</td>
</tr>
<tr>
<td>3</td>
<td>1</td>
<td>13 ¾” hand slips</td>
</tr>
<tr>
<td>4</td>
<td>2</td>
<td>350T 13 ¾” spider elevator slips</td>
</tr>
<tr>
<td>5</td>
<td>2</td>
<td>13 ¾” spider slips</td>
</tr>
<tr>
<td>6</td>
<td>1 set</td>
<td>BJ Type BB tongs, dressed to 13 ¾”</td>
</tr>
<tr>
<td>7</td>
<td>1</td>
<td>13 ¾” plug dropping head</td>
</tr>
<tr>
<td>8</td>
<td>1 set</td>
<td>13 ¾” top and bottom cementing plugs</td>
</tr>
<tr>
<td>9</td>
<td>1</td>
<td>13 ¾” circulating swedge c/w 2” lo-torc valve</td>
</tr>
<tr>
<td>10</td>
<td>4</td>
<td>13 ¾” Clamp on protectors</td>
</tr>
<tr>
<td>11</td>
<td>1</td>
<td>13 ¾” power tong</td>
</tr>
<tr>
<td>12</td>
<td>1</td>
<td>Power unit for tong</td>
</tr>
<tr>
<td>13</td>
<td>1</td>
<td>13 ¾” casing drift</td>
</tr>
<tr>
<td>14</td>
<td>1</td>
<td>13 ¾” cementing plugs</td>
</tr>
<tr>
<td>15</td>
<td>2</td>
<td>Spare couplings</td>
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<td>13 ¾” cement float shoe</td>
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<tr>
<td>17</td>
<td>1</td>
<td>13 ¾” cement float collar</td>
</tr>
<tr>
<td>18</td>
<td>1 lot</td>
<td>13 ¾” bow spring centralizers</td>
</tr>
<tr>
<td>19</td>
<td>1 lot</td>
<td>13 ¾” positive centralizers</td>
</tr>
<tr>
<td>20</td>
<td>1 lot</td>
<td>13 ¾” stop rings c/w spiral nails</td>
</tr>
<tr>
<td>21</td>
<td>1 lot</td>
<td>Centralizers nails</td>
</tr>
<tr>
<td>22</td>
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<td>Thread lock</td>
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<tr>
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<td>Casing dope (API)</td>
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<td>13 ¾” landing joint</td>
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<td>Slip Type casing hanger</td>
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<td>Test plug</td>
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<tr>
<td>28</td>
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<td>13 ¾” cup tester c/w spare cup</td>
</tr>
</tbody>
</table>

2.3.3 9 ½” casing

Following is the equipment checklist for running 9 ½” casing.

**Table 6-3: Equipment required for running 9 ½” casing**

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<thead>
<tr>
<th>Item</th>
<th>Quantity</th>
<th>Description</th>
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</thead>
<tbody>
<tr>
<td>1</td>
<td>1</td>
<td>9 ½” side door elevators</td>
</tr>
<tr>
<td>2</td>
<td>1</td>
<td>9 ½” single joint elevators</td>
</tr>
<tr>
<td>3</td>
<td>1</td>
<td>9 ½” casing drift</td>
</tr>
<tr>
<td>4</td>
<td>1</td>
<td>9 ½” hand slips</td>
</tr>
<tr>
<td>5</td>
<td>2</td>
<td>350T 9 ½” spider elevator</td>
</tr>
<tr>
<td>6</td>
<td>2</td>
<td>9 ½” spider slips</td>
</tr>
</tbody>
</table>
### 2.3.4 7” Casing

Following is the equipment checklist for running 7” casing.

**Table 6-4: Equipment checklist for running 7” casing**

<table>
<thead>
<tr>
<th>Item</th>
<th>Quantity</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1</td>
<td>7” side door elevators</td>
</tr>
<tr>
<td>2</td>
<td>1</td>
<td>7” single joint elevators</td>
</tr>
<tr>
<td>3</td>
<td>1</td>
<td>7” casing drift</td>
</tr>
<tr>
<td>4</td>
<td>1</td>
<td>7” hand slips</td>
</tr>
<tr>
<td>5</td>
<td>2</td>
<td>350T 7” single elevator / slips</td>
</tr>
<tr>
<td>6</td>
<td>2</td>
<td>7” spider slips</td>
</tr>
<tr>
<td>7</td>
<td>1</td>
<td>7” plug dropping head</td>
</tr>
<tr>
<td>8</td>
<td>1 set</td>
<td>7” top and bottom cement plugs</td>
</tr>
<tr>
<td>9</td>
<td>1</td>
<td>7” circulating swedge c/w 2” Lo-torc valve</td>
</tr>
<tr>
<td>10</td>
<td>1</td>
<td>7” power tong</td>
</tr>
<tr>
<td>11</td>
<td>1</td>
<td>Power unit for tong</td>
</tr>
<tr>
<td>12</td>
<td>1</td>
<td>Travel cutter dressed to 7”, if required</td>
</tr>
<tr>
<td>13</td>
<td>2</td>
<td>7” casing pup joints</td>
</tr>
<tr>
<td>14</td>
<td>2</td>
<td>7” couplings</td>
</tr>
<tr>
<td>15</td>
<td>1</td>
<td>7” cement float shoe</td>
</tr>
<tr>
<td>16</td>
<td>1</td>
<td>7” cement float collar</td>
</tr>
</tbody>
</table>

**Item**

1 7” side door elevators
2 7” single joint elevators
3 7” casing drift
4 7” hand slips
5 2 350T 7” single elevator / slips
6 2 7” spider slips
7 1 7” plug dropping head
8 1 set 7” top and bottom cement plugs
9 1 7” circulating swedge c/w 2” Lo-torc valve
10 1 7” power tong
11 1 Power unit for tong
12 1 Travel cutter dressed to 7”, if required
13 2 7” casing pup joints
14 2 7” couplings
15 1 7” cement float shoe
16 1 7” cement float collar
### 2.3.5 7” Liner

Following is the equipment checklist for running 7” liner.

**Table 6-5: Equipment checklist for running 7” liner**

<table>
<thead>
<tr>
<th>Item</th>
<th>Quantity</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>2</td>
<td>7” side door elevators</td>
</tr>
<tr>
<td>2</td>
<td>2</td>
<td>7” single joint elevators c/w swivel sling</td>
</tr>
<tr>
<td>3</td>
<td>2</td>
<td>7” rotary hand slips</td>
</tr>
<tr>
<td>4</td>
<td>2</td>
<td>Power tong dressed for 7” casing</td>
</tr>
<tr>
<td>5</td>
<td>2</td>
<td>Hydraulic power unit for above</td>
</tr>
<tr>
<td>6</td>
<td>2</td>
<td>Torque – turn units (if required)</td>
</tr>
<tr>
<td>7</td>
<td>6</td>
<td>Spare casing collars</td>
</tr>
<tr>
<td>8</td>
<td>1</td>
<td>7” casing spear c/w grapple / pack-off and stop ring. (Specify weight)</td>
</tr>
<tr>
<td>9</td>
<td>As required</td>
<td>7” centralizers(as per simulation run)</td>
</tr>
<tr>
<td>10</td>
<td>As required</td>
<td>7” stop collars</td>
</tr>
<tr>
<td>11</td>
<td>1</td>
<td>7” casing drift (Teflon drift for CRA casing)</td>
</tr>
<tr>
<td>12</td>
<td>As required</td>
<td>Casing dope (API)</td>
</tr>
<tr>
<td>13</td>
<td>As required</td>
<td>Thread lock</td>
</tr>
<tr>
<td>14</td>
<td>1 set</td>
<td>7” casing liner hanger</td>
</tr>
<tr>
<td>15</td>
<td>1</td>
<td>Cement head with heavy duty swivel and dart marker</td>
</tr>
<tr>
<td>16</td>
<td>1</td>
<td>7” circulating swedge c/w 2” Lo-torc valve</td>
</tr>
<tr>
<td>17</td>
<td>1 set</td>
<td>Setting and cementing equipment (ball, plug…)</td>
</tr>
<tr>
<td>18</td>
<td>1</td>
<td>Cementing Kelly</td>
</tr>
<tr>
<td>19</td>
<td>1</td>
<td>7” casing drift</td>
</tr>
</tbody>
</table>

### Item

<table>
<thead>
<tr>
<th>Item</th>
<th>Quantity</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>17</td>
<td>As required</td>
<td>7” open hole centralizers</td>
</tr>
<tr>
<td>18</td>
<td>As required</td>
<td>7” positive centralizers</td>
</tr>
<tr>
<td>19</td>
<td>As required</td>
<td>7” stop rings c/w spiral nails</td>
</tr>
<tr>
<td>20</td>
<td>As required</td>
<td>Centralizer nails</td>
</tr>
<tr>
<td>21</td>
<td>As required</td>
<td>Thread lock</td>
</tr>
<tr>
<td>22</td>
<td>As required</td>
<td>Casing dope (API)</td>
</tr>
<tr>
<td>23</td>
<td>1</td>
<td>7” landing joint</td>
</tr>
<tr>
<td>24</td>
<td>1</td>
<td>7” casing hanger</td>
</tr>
<tr>
<td>25</td>
<td>1 lot</td>
<td>Wellhead equipment</td>
</tr>
<tr>
<td>26</td>
<td>1</td>
<td>Test plug</td>
</tr>
<tr>
<td>27</td>
<td>1</td>
<td>7” cup tester c/w spare cup</td>
</tr>
<tr>
<td>28</td>
<td>1</td>
<td>Cement head</td>
</tr>
<tr>
<td>29</td>
<td>1 set</td>
<td>Cementing plugs</td>
</tr>
<tr>
<td>30</td>
<td>As required</td>
<td>Liner Top Packer</td>
</tr>
</tbody>
</table>
3. Casing Centralization

All centralization programs must be designed to have minimum of 80% casing stand-off.

Following are the centralization programs for the different casing sizes.

3.1 30” Conductor Centralization

Table 6-6: 30” conductor centralization program

<table>
<thead>
<tr>
<th>No. of Centralizers</th>
<th>Centralizers Type</th>
<th>Centralizers Repetition</th>
<th>Centralizers location</th>
<th>Remarks</th>
</tr>
</thead>
<tbody>
<tr>
<td>One</td>
<td>Open Hole</td>
<td>Every joint</td>
<td>Middle of the joint</td>
<td>Use centralizers that allow passage of Macaroni tubes for Cement Top Job</td>
</tr>
<tr>
<td>One</td>
<td>Open Hole</td>
<td>One joint</td>
<td>10 ft below the cellar</td>
<td></td>
</tr>
</tbody>
</table>

3.2 18 ½” Casing Centralization

1) Case 1: 18 ½” conductor centralization

Table 6-7: 18 ½” Conductor centralization program

<table>
<thead>
<tr>
<th>No. of Centralizers</th>
<th>Centralizers Type</th>
<th>Centralizers Repetition</th>
<th>Centralizers location</th>
<th>Remarks</th>
</tr>
</thead>
<tbody>
<tr>
<td>one</td>
<td>Open Hole</td>
<td>Every joint</td>
<td>Middle of the joint</td>
<td>Use centralizers that allow passage of Macaroni tubes for Cement Top Job</td>
</tr>
<tr>
<td>one</td>
<td>Open Hole</td>
<td>One joint</td>
<td>10 ft below the cellar</td>
<td></td>
</tr>
</tbody>
</table>

2) Case 2: 18 ½” casing centralization

Table 6-8: 18 ½” casing centralization program

<table>
<thead>
<tr>
<th>No. of Centralizers</th>
<th>Centralizers Type</th>
<th>Centralizers Repetition</th>
<th>Centralizers location</th>
<th>Remarks</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>Open Hole</td>
<td>First joint</td>
<td>One 5 ft and one 25 ft above the shoe</td>
<td>Centralizers to be made up over stop collar</td>
</tr>
<tr>
<td>2</td>
<td>Open Hole</td>
<td>Next 3 joints</td>
<td>Every 15 ft</td>
<td>Centralizers to be made up over stop collar</td>
</tr>
<tr>
<td>1</td>
<td>Open Hole</td>
<td>Every 3 joints up to the previous casing shoe</td>
<td>Middle of the joint</td>
<td>Centralizers to be made up over stop collar</td>
</tr>
<tr>
<td>1</td>
<td>Positive</td>
<td>Every 3 joints in the cased</td>
<td>Middle of the joint</td>
<td>Centralizers to be made up</td>
</tr>
</tbody>
</table>

### 3.3 13 ⅜” Casing Centralization

#### 1) Case 1: 13 ⅜” casing centralization for vertical hole

<table>
<thead>
<tr>
<th>No. of Centralizers</th>
<th>Centralizers Type</th>
<th>Centralizers Repetition</th>
<th>Remarks</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>Open Hole</td>
<td>First joint</td>
<td>One 5 ft and one 25 ft above the shoe</td>
</tr>
<tr>
<td>2</td>
<td>Open Hole</td>
<td>Next 3 joints</td>
<td>20 ft a part</td>
</tr>
<tr>
<td>1</td>
<td>Open Hole</td>
<td>Every 3 joints</td>
<td>Middle of the joint</td>
</tr>
<tr>
<td>1</td>
<td>Positive</td>
<td>Every 3 joints</td>
<td>Middle of the joint</td>
</tr>
<tr>
<td>2</td>
<td>Positive</td>
<td>Last 4 joints</td>
<td>20 ft apart</td>
</tr>
</tbody>
</table>

#### 2) Case 2: 13 ⅜” casing centralization for deviated hole

In case of running 13 ⅜” casing in 17 ½” deviated hole a simulation run must be made by the centralizers supplier to have a minimum of 80% casing standoff.
3.4 9 5/8” Casing Centralization

1) Case 1: 9 5/8” casing centralization for a vertical hole

Table 6-10: 9 5/8” casing centralization program

<table>
<thead>
<tr>
<th>No. of Centralizers</th>
<th>Centralizers Type</th>
<th>Centralizers Repetition</th>
<th>Centralizers location</th>
<th>Remarks</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>Open Hole</td>
<td>First joint</td>
<td>One 5 ft and one 25 ft above the shoe</td>
<td>Centralizers to be made up over stop collar</td>
</tr>
<tr>
<td>2</td>
<td>Open Hole</td>
<td>Next 3 joints</td>
<td>20 ft a part</td>
<td>Centralizers to be made up over stop collar</td>
</tr>
<tr>
<td>1</td>
<td>Open Hole</td>
<td>Every 3 joints Up to the previous casing shoe</td>
<td>Middle of the joint</td>
<td>Centralizers to be made up over stop collars</td>
</tr>
<tr>
<td>1</td>
<td>Positive</td>
<td>Every 3 joints in the cased hole</td>
<td>20 ft a part</td>
<td>Centralizers to be made up between two stop collars</td>
</tr>
<tr>
<td>2</td>
<td>Positive</td>
<td>Last 3 joint</td>
<td>Middle of the joint</td>
<td>Centralizer to be made between two stop collars</td>
</tr>
<tr>
<td>2</td>
<td>Positive</td>
<td>Last joint</td>
<td>10 ft and 30 ft below cellar</td>
<td>Centralizer to be made between two stop collars</td>
</tr>
</tbody>
</table>

2) Case 2: 9 5/8” casing centralization for deviated hole

In case of running 9 5/8” casing in 12 1/4” deviated hole a simulation run must be made by the centralizers supplier to have a minimum of 80% casing stand-off.

3.5 7” Liner Centralization

The centralization of 7” liner is very critical because most of the time it is across the reservoir. It is essential to have casing stand-off over 80% in order to reach the required reservoir isolation.

Rotating centralizers are highly recommended in 7” liner to reduce torque (in case of rotating liners) and to achieve the required stand-off percentage at the same time.

For rotating liners and for deviated wells use rigid centralizers and for vertical wells use Bow-Type centralizers.
Also it is essential to perform simulation for the centralization program using the actual hole survey to determine the number and the locations of centralizers.

4. Running Casing

4.1 General Guidelines

- Remove pin and box protectors from casing and accessory pieces, and thoroughly clean the connections, removing all previously applied thread or storage compound.

- When moving pipe from the racks to the catwalk, ensure that joints are not dropped or allowed to hit against other casing or rig equipment. Casing should be pulled up to the V-door with a choker, and then single joint elevators used to pull the casing joint into the derrick. Thread protectors must be in place on both pin and box connections any time the pipe or accessories are moved.

- Once the casing has been pulled into the derrick, the pin end thread protector can be removed, thread compound applied and the joint stabbed.

- In stabbing the joint, use stabbing guides, lower the casing slowly to avoid connection damage, and ensure that the connection is aligned before starting rotation. For large casing, and if there is any misalignment of the blocks over the rotary, a man on the stabbing board can be of great assistance.

- If the casing does not stab correctly or jams, the pin should be picked up from the box, both connections cleaned, inspected, and repaired (remove any filings or wickers), thread compound re-applied, and the connection re-stabbed.

- Once the joint is stabbed, make-up can proceed, with the connection being spun up slowly initially, ensuring that the connection is not cross-threaded or jammed.

- API Round and Buttress connections are assembled to position; the assembly torque values provided are representative of the torque range required to attain the power-tight position based on nominal conditions, and must be used only as a guide. Torque must relate to the make-up position, and as a result, the torques used in the field for a given connection can vary from those listed.

- Casing must be lowered carefully, first to avoid shock loads to the casing string, but also to prevent pressure surges which may damage downhole formations. The slips must not be set until all downward
motion of the casing string has stopped. Great care should be exercised to ensure that the string does not spud the bottom of the hole, as the compressive loads can cause the string to buckle and/or connections to loosen with the subsequent risk of failure in service.

- Note that often there is a predetermined running order for casing and related accessories due to design criteria or downhole conditions. It is vital that this order be followed, and in the event that a specific joint of casing cannot be identified with respect to its weight or grade, the joint should not be run.
5. Standard Casing Data

5.1 Casing Dimensions and Capacities

Table 6-11: Casing dimension and capacities

<table>
<thead>
<tr>
<th>OD (in)</th>
<th>Nominal Weight (Lb/ft)</th>
<th>Wall Thickness (in)</th>
<th>ID (in)</th>
<th>Drift Diameter (in)</th>
<th>Cu.ft/ft</th>
<th>Ft/cu.ft</th>
<th>Bbls/ft</th>
<th>Ft/bbl</th>
</tr>
</thead>
<tbody>
<tr>
<td>4.5&quot;</td>
<td>12.6</td>
<td>0.271</td>
<td>3.958</td>
<td>3.833</td>
<td>0.0855</td>
<td>11.69</td>
<td>0.0152</td>
<td>65.65</td>
</tr>
<tr>
<td>5.5&quot;</td>
<td>20</td>
<td>0.361</td>
<td>4.778</td>
<td>4.653</td>
<td>0.1241</td>
<td>8.06</td>
<td>0.0222</td>
<td>45.04</td>
</tr>
<tr>
<td>7&quot;</td>
<td>29</td>
<td>0.408</td>
<td>6.184</td>
<td>6.059</td>
<td>0.2086</td>
<td>4.79</td>
<td>0.0371</td>
<td>26.95</td>
</tr>
<tr>
<td>9 ¾&quot;</td>
<td>47</td>
<td>0.472</td>
<td>8.681</td>
<td>8.525</td>
<td>0.4110</td>
<td>2.43</td>
<td>0.0732</td>
<td>13.66</td>
</tr>
<tr>
<td></td>
<td></td>
<td>53.5</td>
<td>8.535</td>
<td>8.379</td>
<td>0.3973</td>
<td>2.52</td>
<td>0.0708</td>
<td>14.12</td>
</tr>
<tr>
<td>13 ¾&quot;</td>
<td>68</td>
<td>0.480</td>
<td>12.415</td>
<td>12.259</td>
<td>0.8406</td>
<td>1.19</td>
<td>0.1497</td>
<td>6.68</td>
</tr>
<tr>
<td></td>
<td></td>
<td>72</td>
<td>12.347</td>
<td>12.191</td>
<td>0.8315</td>
<td>1.20</td>
<td>0.1481</td>
<td>6.75</td>
</tr>
<tr>
<td>18 ¾&quot;</td>
<td>87.5</td>
<td>0.435</td>
<td>17.755</td>
<td>17.567</td>
<td>1.7193</td>
<td>0.58</td>
<td>0.3062</td>
<td>3.27</td>
</tr>
</tbody>
</table>
### 5.2 Casing Minimum Performance Properties

#### Table 6-12: Casing minimum performance properties

<table>
<thead>
<tr>
<th>OD (m)</th>
<th>Nominal Weight (lb/ft)</th>
<th>Connection Type</th>
<th>Grade</th>
<th>Collapse Resistance (psi)</th>
<th>Pipe-Body Yield Strength (1000 lb)</th>
<th>Burst Pressure (psi)</th>
<th>Optimum Make Up Torque (ft.lb)</th>
</tr>
</thead>
<tbody>
<tr>
<td>4.5&quot;</td>
<td>12.6</td>
<td>Vam</td>
<td>L-80</td>
<td>7500</td>
<td>288</td>
<td>8430</td>
<td>4700</td>
</tr>
<tr>
<td>5.5&quot;</td>
<td>20</td>
<td>Vam</td>
<td>L-80</td>
<td>8830</td>
<td>466</td>
<td>9190</td>
<td>8000</td>
</tr>
<tr>
<td>7&quot;</td>
<td>29</td>
<td>NK3SB</td>
<td>L-80</td>
<td>7020</td>
<td>676</td>
<td>8160</td>
<td>9700</td>
</tr>
<tr>
<td></td>
<td>29</td>
<td>Vam</td>
<td>L-80</td>
<td>7020</td>
<td>676</td>
<td>8160</td>
<td>8700</td>
</tr>
<tr>
<td>9 ½&quot;</td>
<td>47</td>
<td>NK3SB</td>
<td>L-80</td>
<td>4760</td>
<td>1086</td>
<td>6870</td>
<td>14500</td>
</tr>
<tr>
<td></td>
<td>53.5</td>
<td>Vam</td>
<td>C-95</td>
<td>7340</td>
<td>1477</td>
<td>9410</td>
<td>11500</td>
</tr>
<tr>
<td>13 ¾&quot;</td>
<td>68</td>
<td>BTC *</td>
<td>K-55</td>
<td>1950</td>
<td>1069</td>
<td>3450</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>72</td>
<td>NK3SB</td>
<td>L-80</td>
<td>2670</td>
<td>1661</td>
<td>5380</td>
<td>20000</td>
</tr>
<tr>
<td>18 ¾&quot;</td>
<td>87.5</td>
<td>BTC *</td>
<td>K-55</td>
<td>630</td>
<td>1367</td>
<td>2250</td>
<td>-</td>
</tr>
</tbody>
</table>

* For all Buttress connections, there are no specific Make up torque values. Gauge should be calibrated to the torque to make up each of several connections to the base of the triangle mark.
SECTION 2

CEMENTING GUIDELINES

1. Introduction

1.1 Cementing General

Good planning, programming and preparation plays an extremely important role in cementing operations, especially as it necessitates the gathering of a quantity of specialized material and equipment, and a number of skilled personnel at a single location. A shortfall in the quantity or quality of material or equipment, or the non availability of a person with the requisite skills could lead to an expensive suspension of operations. This Section provides reader of the best practices to plan, design and implement a successful cement operation.

1.2 Cementing Responsibilities

1.2.1 Cement Group

Cement Group provides technical, administrative and logistic support to the rig and thereby enables the safe delivery of the correct quantity of product and personnel at optimum cost.

Cement Group is responsible of:

- All aspects of cementing servicing from the design stage to the execution.
- Development of cementing policy and procedures in close consultation with the Operations Teams.
- Cementing technical auditing and trouble shooting.
- New cementing materials

1.2.2 Drilling Contractor

The following minimum checks and procedures are to be performed by the drilling contractor

- Air up all tanks the day before the cement job, check for leaks. Carry out repairs immediately.
- Pressure test and physically check all supply lines and valves from the rig to the cement unit.
• Prepare displacement tanks; make sure the mud volumes are correct.
• Prepare separate tanks for return with accurate measurements.
• Make sure the correct displacement efficiencies are correctly measured.
• Make sure the pump displacement lines are blocked up correctly.
• Report to the Drilling Supervisor when all the above inspections have been completed.

1.2.3 Cement Operator

The cement operator’s duties are:

• Maintain and operate the cementing installation and all associated equipment on the rig to the highest standards of reliability, and ensure that the unit has valid certification, including certification for any densitometer with a radio-active source.
• Record stock levels of cement and additives and maintain quality control. Maintain adequate spare parts and consumables to support the operations. Maintain a log book of all materials used and delivered.
• Carry out individual cement calculations and verify calculations performed by the wellsite drilling engineer and Drilling Supervisor.
• Perform the cement job as per the programme specified by the company, including the use of liquid additive dispensing units and data recording devices.
• Obtain representative samples of cements and additives and forward these in good time for laboratory testing, properly packaged.
• Check the cement unit and equipment and ensure the following:
  o Unit and lines are pressure tested to minimum 1000 psi above casing test pressure using a chart recorder.
  o Unit displacement tank barrel scale is accurate.
  o Displacement tank valves do not leak, and are easily operable.
  o Low pressure mixing system is flushed through.
Packings on mix pumps are operable.
- Pressure on mix pumps is more than adequate for mixing.
- Unit’s computer is in good working conditions.
- Jets in mixer are correct.
- Bypass valve on mix manifold is working.
- Bypass on mixer is open (manually).
- Engine oil and water are at correct levels.
- Oil in pumps is at correct levels.
- Hoses are serviceable.
- Hopper is serviceable.
- Cement head, i.e. valves, threads, indicators and plug locator pins are all operable.
- Volume of additives is sufficient to provide 100% of job requirements.
- Water supply rate to displacement tanks or batch tank exceeds maximum estimated requirement.
- Batch mixer and Air compressor is operating correctly.
- Each cement silos is marked with the type of cement inside.
- Dust arrestors are installed.

### 1.2.4 Field Cement Engineer (if present)

- Ensure cement, additive and mixwater samples are sent in correctly marked and packaged.
- Collect samples during the cement job.
- Confirm stock levels of cement and additives.
- Collate downhole temperature data as a check on cement slurry design. Compare to test temperature.
- Witness and check quality control of caliper logs (if present).
- Compute slurry volumes from caliper (if present).
- Prepare individual calculations for the cement job, Compare results with the separate calculations carried out by the Drilling Supervisor and cementer.
- Verify and monitor mixwater volumes, displacement volumes and pressure during the cement job.
• Supervise preparation of spacers, cement and additives. Ensure cement is fluffed as per recommended procedure.

• Prepare all cementation reports.

1.2.5 Drilling Supervisor

• Inform the RM and Driller of:
  - The volume of each type of mix water to be used for both lead and tail cement jobs.
  - From which mud pit each type of mix water will be drawn.
  - The expected gain, per barrel of mix water blended with cement, for both lead and tail slurries.
  - The expected total volume of returns during the cement job and the expected overall increase in pit volume.

• Supervise the FCE, if present, cementers and drilling contractor in the performance of their duties.

• Prepare individual calculations for the cement job.

• Check the mud pumps efficiency.

• Approve all reports, worksheets and job tickets.

• Co-ordinate the planning and execution of the cement job. Ensure that all relevant personnel are issued with a detailed programme of the cement job, highlighting individual responsibilities. The detailed programme must include volumes, pressures and pump rates for the cementing and displacing operations. Contingency plans must also be drawn up for any equipment failure, etc. Procedures must be written to cover alternative mix water supply, rig pump failure, alternative mixwater and displacement valve measurement and procedures if predicted pressures are exceeded or return volumes insufficient to maintain displacement with mud.

1.2.6 Mud Engineer

• Check the mix-water for contamination and salinity.

• Ensure that a sufficient volume of mud is available on the surface prior to commencement of the cementation.

• Monitor pit volumes throughout the cementation.

• Calibrate mud tanks and check the mud and cement returns
1.2.7 Senior Cement Engineer

The Senior Cement Engineer will have the following responsibilities:

• Discuss and agree with the operation teams on the required cement slurries and volumes.
• Request, review and agree on the cement recipe received from ADCO lab.
• Prepare and review the cement job program, discuss any changes needed with the operation team.
• Report to Team Leader (Mud and Cement)
• Ensure that a comprehensive administrative recording and filing system is maintained to assist the Drilling Engineers as a part of lesson learnt
• Be responsible for the Cement Engineers and ensure full utilization all this within the boundaries of HSE.
• Ensure applications and recording of Cement Quality Parameters (CQPs) evaluation.

2. Cementing General Guidelines

The operation checklist is to be used and referred to at all times when planning and preparing for cementing operations.

2.1 Prior to Cement Job

• The following procedures must be strictly followed for cement formulation
  o ADCO laboratory is sending first a PRELIMINARY recipe (typical formulation for the type of operation & conditions) by fax to the rig for ordering purposes (cement, blends & additives).
  o Actual samples of cement &/or blends delivered to the rigs are tested by the service company & ADCO laboratory.
  o Service Company laboratory results will be communicated to ADCO laboratory for review and must NOT be sent to the rig directly.
  o ADCO laboratory is sending the final (revised) recipe (based on actual cement samples for the job) by fax to the rig approved by SCE.
• Ensure that the FINAL ADCO laboratory WRITTEN recipe approved by C&MDTL is implemented during the cementing job. Verbal communication of formulations must be avoided.

• Ensure the following samples are sent to ADCO lab prior to cement job for lab testing:

  - Cement from each silo 10 kg
  - Mix water 1 gal
  - Liquid additives 500 ml

• Ensure thickening time is adequate for anticipated duration of the job.

• Ensure calipers (if presented) have been calibrated inside previous casing shoe. Compare different calipers with each other. Check for any off scale washouts on the caliper.

• Calculate any reduction in hydrostatic head due to cement spacers. Check overbalance. Assume gauge hole. Ensure overbalance is maintained through all stages of the job.

• Beware of gel strength development in slurries particularly at elevated temperatures in the range of 180-250 deg F. Be particularly concerned to minimize unnecessary shutdowns during mixing and pumping.

• Check maximum expected ECD against shoe strength.

• Ensure sufficient chemicals on location for double the estimated quantity, providing 100% contingency.

• Ensure that a pressurized mud balance for determining densities of critical slurries is available. Many Types of slurry will entrain air which will cause them to weight much less than downhole density in a standard mud balance.

• Ensure that all necessary equipment is on rig and checked out. In particular, when surface release cement plugs are to be used, check the condition of the surface cement head.

• Ensure that the cement unit and all lines to the rig floor are flushed through and pressure tested as specified several hours before cementing is to take place.

• Check the mix water transfer line for leaks.

• Check chloride content of the mix water.
• Ensure mud pumps are hooked up correctly to the displacement position, all valves and gates checked for leak.

• Both the Driller and the Mud Engineer are to prepare pit and flowlines for the expected total returns. (The system must be prepared to accept the total volume returned equal to the volume of slurry and spacers are to be pumped).

• The Driller and the Mud Engineer are to record the volumes in each individual pit and the total volume in the pits.

• After the mud pits have been prepared, no mud is to be transferred or dumped without prior permission from the Drilling Supervisor.

• Recheck cementing program for the risk of casing Collapse, Burst and Floatation.

2.2 During the Cement Job

• Ensure the following samples are taken at regular intervals during the cement jobs in case of problems:

  - Cement from Surge Tank 10 kg
  - Actual Mix Water with Additives 1 gal
  - Drill Water 1 gal
  - Individual Liquid Additives 500 ml
  - Slurry Samples 5-10 cups

Check density of the liquid additives prior to use.

Notes:

  o Mix water samples should be collected at the beginning, middle and end of the lead and tail slurry.
  o Retain the slurry samples for observation.

• Maintain plot of displacement vs. top of cement and also position of top plug. Compare theoretical and actual pressures.

• The Drilling Supervisor / Field Cement Engineer to inform both the Mud Engineer and the Driller periodically of the amounts of mix water used.

• Ensure cement operator changes displacement tanks correctly to minimize error in slurry or displacement volumes.

• Avoid the possibility of pumping diluted cement or even water into casing before the top plug is released.
• Using spacers and flushes is very effective in enhancing the cement job because the spacer improve removal of gelled mud, which allowing a better cement bond.

In order to obtain the maximum benefits of the spacers, consider the following.

  o Bump the spacer fluid at an optimized rate.
  o Provide a contact time and volume of spacer that will remove the greatest possible amount of mud cake, as guideline use a volume of spacer which occupies 500 ft in annulus or 10 min. contact time.

• Moving the pipe before and during the cement job improve the displacement efficiency. Aids in cutting removal and break mud gel strength. If the pipe poorly centralized, the movement can create flow path through the casing and allowing the slurry to circulate completely around the casing.

In some cases pipe movement is not recommended specially when losses is experienced and the surge produced by the pipe movement will increase the losses

• Displacement rate is very effective in cement job quality, the best result could be obtained when the spacer and/or cement is pumped at maximum allowable rate. The displacement rates should be limited to the maximum allowable ECD or as per the job simulation.

• Conditioning mud prior to the cement job helps in improving the cement job quality. During conditioning mud we need to

  o Break mud gel
  o Lower yield Point
  o Keep solids<10%
  o Circulate>95% of the total hole capacity (minimum of 2 hole cycles)

• Physically ascertain the amount of fluid pumped from the pits, and check that the pits are dropping by the requisite amount during the displacement (don’t rely on pump stroke counters).

• If more than one pit is required equalize across two pits and pump the displacement, if that is not possible then displace a volume from one pit, stop the pumps, line up to the second pit and complete the displacement.

• Displace the cement with mud. Determine the displacement volume, pump strokes and pumping time at which the displacement rate should be reduced prior to bumping the plugs. Displace cement at maximum rate allowable from pressure consideration unless advised otherwise.
• The active pit gain is to be monitored continuously during cementing. Expect additional return volumes during mixing and reduced return rates during initial displacing. Ensure any losses are noted.

• Displace from the cementing unit in the following cases:
  o When no rig pumps available. Control volume by measuring from mud tanks as well as cement unit displacement tanks.
  o When placing cement plugs or cementing through drill pipe.
  o Liner cementations.

• If rig pump is used, have cementer’s pump unit ready to take over to pump the plugs in case the pressure becomes excessive. Record all mixing, displacing, pumping, etc on pressure chart.

• The Mud Engineer / Driller are to record the total volume in the pits and inform ADCO Supervisor / Drilling Engineer of the volume gained (or lost) during the entire cement job.

• After bumping top plug, release pressure, measure returns and check for backflow.

• If there is backflow, bump back the amount of backflow only and re-pressure the casing. If there is still backflow, hold pressure and wait until the cement is hard before repeating the test.

• Pressure test casing immediately after bumping plug (15 min. API).

• Every single job with the cement unit (regardless of type or importance) MUST be recorded with the unit computer (pump rate, pumping pressure, cumulative volume, ... etc) and the relevant chart (properly documented) provided to the DS with the job log and with the contractor invoice.
3. **18 ⅝” Casing Cementing**

The 18 ⅝” casing should be cemented using either Stinger Technique of Plug and bump technique.

### 3.1 18 ⅝” Casing Cementing Job Calculations

#### 3.1.1 Stinger Technique

**Assumptions:**

- D = Annulus Capacity between 18 ⅝” casing and 26” hole or 22” hole (cu.ft/ft)
- E = Slurry Yield (cu.ft/sk)
- F = Slurry Mix Water (gal/sk)
- G = Drill Pipe Capacity (bbl/ft)
- M = Annulus capacity between 18 ⅝” casing and 30” conductor (cu.ft/ft)

![Figure 6-1: Cementing 18 ⅝” Casing with cementing stinger](image)
## Calculation Sheet for 18 ⅝” Casing Cementing Job (Stinger Technique)

Table 6-13: 18 ⅝” casing cementing calculations (Stinger Technique)

<table>
<thead>
<tr>
<th>Elevation / Depth</th>
<th>Slurry Volume (H) (cu.ft)</th>
<th>Number of Sacks (I) (sk)</th>
<th>Slurry Mix Water (J) (gal)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tail Slurry</td>
<td>Hₜ = A x D x Open Hole Excess = ………..cu.ft</td>
<td>Iₜ = Hₜ / Eₜ = ………..sk</td>
<td>Jₜ = Iₜ x Fₜ = ………..gal</td>
</tr>
<tr>
<td></td>
<td>95 bbls to be used</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Lead Slurry</td>
<td>Hₗ =( B x D x Open Hole Excess) + (K x M x Cased Hole Excess) = ………..cu.ft</td>
<td>Iₗ = Hₗ / Eₗ = ………..sk</td>
<td>Jₗ = Iₗ x Fₗ = ………..gal</td>
</tr>
</tbody>
</table>

Displacement = G x (A+B+C+K) = ………..bbl

**Note:**
- Open Hole Excess = 50%
- Cased Hole Excess = 10%
3.1.2 Plug and Bump Technique

**Assumptions:**

- \( F = \text{Annulus Capacity between 18 \( \frac{5}{8} \)" casing and 26" or 22" hole (cu.ft/ft)} \)
- \( G = \text{Annulus Capacity between 18 \( \frac{5}{8} \)" casing and 30" conductor (cu.ft/ft)} \)
- \( H = 18 \frac{5}{8}\" \text{casing capacity (bbl/ft)} \)
- \( I = \text{Slurry Yield (cu.ft/sk)} \)
- \( J = \text{Slurry Mix Water (gal/sk)} \)

![Diagram of cementing 18 \( \frac{5}{8} \)" Casing (Plug and Bump Technique)](image)

Figure 6-2: Cementing 18 \( \frac{5}{8} \)" Casing (Plug and Bump Technique)
### Calculation Sheet for 18 ¾” Casing Cementing Job (plug and Bump Technique)

**Table 6-14: 18 ¾” casing cementing calculations (Bump and Plug technique)**

<table>
<thead>
<tr>
<th>Elevation/Depth Data (See Figure 6-2)</th>
<th>Slurry Volume (K)</th>
<th>Number of Sacks (L)</th>
<th>Slurry Mix Water (M) (L)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>(cu.ft)</td>
<td>(sk)</td>
</tr>
<tr>
<td>A = ft</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>B = ft</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>C = ft</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>D = ft</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>G = ft</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Tail Slurry**

\[ K_T = (A \times H) + \{(B \times F) \times \text{Open Hole Excess}\} = \ldots \ldots \text{cu.ft} \]

\[ L_T = K_T / I_T \]

\[ = \ldots \ldots \text{sk} \]

\[ M_T = J_T \times L_T \]

**Lead Slurry**

\[ K_L = (C \times F \times \text{Open Hole Excess}) + \{(D \times G) \times \text{Cased Hole Excess}\} = \ldots \ldots \text{cu.ft} \]

\[ L_L = K_L / I_L \]

\[ = \ldots \ldots \text{sxs} \]

\[ M_L = J_L \times L_L \]

**Displacement**

\[ = H \times (B+C+D+E-A) = \ldots \ldots \text{bbl} \]

**Note:**
- Open Hole Excess = 50%
- Cased Hole Excess = 10%
### 3.2 18 ⅝” Casing Cement Slurry

Table 6-15: 18 ⅝” casing cement slurry composition and properties

<table>
<thead>
<tr>
<th>Casing Setting Depth Range (ft)</th>
<th>Slurry</th>
<th>Weight (pcf)</th>
<th>Thickening Time (Hrs)</th>
<th>Compressive Strength</th>
<th>Slurry</th>
<th>Weight (pcf)</th>
<th>Thickening Time (Hrs)</th>
<th>Compressive Strength</th>
</tr>
</thead>
<tbody>
<tr>
<td>100-500</td>
<td>&quot;G&quot;</td>
<td>118</td>
<td>&gt;= 4</td>
<td>&gt;= 2700 psi @105 Deg F</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>500-2800</td>
<td>Light Weight</td>
<td>86</td>
<td>&gt;=6</td>
<td>&gt;= 750 psi @ 105 Deg F</td>
<td>&quot;G&quot;</td>
<td>118</td>
<td>&gt;= 4</td>
<td>&gt;= 2700 psi @110 Deg F</td>
</tr>
</tbody>
</table>

**Note:**
- Excess on open hole = 50%
- Excess on cased hole = 10%

For detailed cementing procedure refer to the relevant Section in Chapter-2 “Drilling Operations Guidelines” of this Volume.
4. 13 ¾” Casing Cementation

4.1 13 ¾” Casing Cementing Job Calculations

Assumptions:

F = Annulus Capacity between 13 ¾” casing and 17 ½” or 16” hole (cu.ft/ft)
G = Annulus Capacity between 13 ¾” casing and 18 ¾” casing (cu.ft/ft)
H = 13 ¾” casing capacity (bbl/ft)
I = Slurry Yield (cu.ft/sk)
J = Slurry Mix Water (gal/sk)

Figure 6-3: Cementing 13 ¾” Casing
## Table 6-16: 13 ⅜” casing cementing calculations

<table>
<thead>
<tr>
<th>Elevation/Depth Data (See Figure 6-3)</th>
<th>Slurry Volume (K) (cu.ft)</th>
<th>Number of Sacks (L) (sk)</th>
<th>Slurry Mix Water (M) (gal)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A = ft</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>B = ft</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>C = ft</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>D = ft</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>E = ft</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

- **Tail Slurry**
  \[K_T = (A \times H) + \{(B \times F) \times \text{Open Hole Excess}\} = \ldots\ldots\text{cu.ft}\]
  \[L_T = K_T / I_T = \ldots\ldots\text{sk}\]
  \[M_T = J_T \times L_T = \ldots\ldots\text{gal}\]

- **Lead Slurry**
  \[K_L = (D \times G \times \text{Cased Hole Excess}) + \{(C \times F) \times \text{Open Hole Excess}\} = \ldots\ldots\text{cu.ft}\]
  \[L_L = K_L / I_L = \ldots\ldots\text{sk}\]
  \[M_L = J_L \times L_L = \ldots\ldots\text{gal}\]

- **Displacement**
  \[H \times (B + C + D + E - A) = \ldots\ldots\text{bbl}\]

**Note:**
- Excess on open hole volumes = 50 - 80% based on the amount of losses during drilling 17 ½” section.
- Excess on cased hole volumes = 10%
### 4.2 13 ¾” Casing Cement Slurry

Table 6-17: 13 ¾” casing cement slurry composition and properties

<table>
<thead>
<tr>
<th>Casing Setting</th>
<th>Lead</th>
<th>Tail</th>
<th>Compressive Strength</th>
<th>Compressive Strength</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depth Range (ft)</td>
<td>Slurry</td>
<td>Weight (pcf)</td>
<td>Thickening Time (Hrs)</td>
<td>Slurry Weight (pcf)</td>
</tr>
<tr>
<td>1000 – 4000</td>
<td>Light Weight</td>
<td>86</td>
<td>≈ 5</td>
<td>“G” 118</td>
</tr>
<tr>
<td>4000 – 6500</td>
<td>Light Weight</td>
<td>80</td>
<td>≈ 6</td>
<td>“G” 118</td>
</tr>
</tbody>
</table>

**Note:**
- Excess on open hole volumes = 50 - 80% based on the amount of losses during drilling 17 ½” section.
- Excess on cased hole volumes = 10%
5. 9 5/8” Casing Cementing

5.1 9 5/8” Casing Cementing Job Calculations

Assumptions

F = Annulus Capacity between 9 5/8” casing and 12 ¼” hole (cu.ft/ft)

G = Annulus Capacity between 9 5/8” casing and 13 3/8” casing (cu.ft/ft)

H = 9 5/8” casing capacity (bbl/ft)

I = Slurry Yield (cu.ft/sk)

J = Slurry Mix Water (gal/sk)

Figure 6-4: Cementing 9 5/8” Casing
### Calculation Sheet for 9 ⅝” Casing Cementing Job

**Table 6-18: 9 ⅝” casing cementing calculations**

<table>
<thead>
<tr>
<th>Elevation / Depth Data (See Figure 6-4)</th>
<th>Slurry Volume (K) (cu.ft)</th>
<th>Number of Sacks (L) (sk)</th>
<th>Slurry Mix Water (M) (gal)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A = ft</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>B = ft</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>C = ft</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>D = ft</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>E = ft</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Tail Slurry</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>K_T = (A x H)+{B x F x Open Hole Excess) =.........cu.ft</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>L_T = K_T / l_T</td>
<td>M_T = J_T x L_T</td>
</tr>
<tr>
<td></td>
<td></td>
<td>=.............sk</td>
<td>=.............gal</td>
</tr>
<tr>
<td><strong>Lead Slurry</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>K_L = (C x F x Open Hole Excess)+(D x G x Cased Hole Excess = ....cu.ft</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>L_L = K_L / l_L</td>
<td>M_L = J_L x L_L</td>
</tr>
<tr>
<td></td>
<td></td>
<td>=.............sk</td>
<td>=.............gal</td>
</tr>
</tbody>
</table>

Displacement = H x (B + C + D + E - A) =.........bbl

**Note:**
- Open Hole Excess = 70%
- Cased Hole Excess = 10%
5.2 9 5/8” Casing Cement Slurry

Table 6-19: 9 3/4” casing cement slurry composition and properties

<table>
<thead>
<tr>
<th>Casing Setting</th>
<th>Lead</th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Depth Range (ft)</td>
<td>Slurry Weight (pcf)</td>
<td>Thickening Time (Hrs)</td>
<td>Compressive Strength Slurry Weight (pcf)</td>
<td>Thickening Time (Hrs)</td>
</tr>
<tr>
<td>5000 – 8000</td>
<td>Light Weight 70-80</td>
<td>≈ 5</td>
<td>≈ 500 psi @ 130 Deg F</td>
<td>&quot;G&quot; cement 118</td>
</tr>
<tr>
<td>8000 – 10000 or across reservoir</td>
<td>Light Weight 100</td>
<td>≈ 6</td>
<td>≈ 1000 psi @ 130 Deg F</td>
<td>&quot;G&quot;+35% SF 118</td>
</tr>
</tbody>
</table>

**Note:**
- Excess on open hole volumes = (70-100)%
- Excess on cased hole volumes = 10%

For detailed cementing procedure refer to the relevant Section in Chapter-2 “Drilling Operations Guidelines” of this Volume.
6. 7” Liner Cementing

6.1 7” Liner Cementing Job Calculations

**Assumptions:**

\[
\begin{align*}
G &= \text{Annulus Capacity between 7” casing and 8 1/2” hole (cu.ft/ft)} \\
H &= \text{Annulus Capacity between 7” casing and 9 5/8” casing (cu.ft/ft)} \\
I &= \text{7” casing capacity (bbl/ft)} \\
J &= \text{Annulus Capacity between drill pipe and 9 5/8” casing (cu.ft/ft)} \\
K &= \text{Slurry Yield (cu.ft/sk)} \\
L &= \text{Slurry Mix Water (gal/sk)} \\
Q &= \text{Drill Pipe Capacity (bbl/ft)}
\end{align*}
\]

![Diagram of 7” Liner Cementation Calculations](image)

Figure 6-5: 7” Liner Cementation Calculations
Table 6-20: 7” liner cementing calculations

<table>
<thead>
<tr>
<th>Elevation / Depth Data (See Figure 6-5)</th>
<th>Slurry Volume (M) (cu.ft)</th>
<th>Number of Sacks (N) (sk)</th>
<th>Slurry Mix Water (O) (gal)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A = ft</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>B = ft</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>C = ft</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>D = ft</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>E = ft</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>F = ft</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

| Tail Slurry                             |                           |                          |                           |
| M_T=(A x I)+{B x G x Open Hole Excess} | N_T = M_T / K_T           | O_T = N_T x L_T          |
|                                        | =.............sk           | =.............gal         |

| Lead Slurry                             |                           |                          |                           |
| M_L=(C x G x Open Hole Excess)+(D x H x cased hole excess)+(E x J x Cased Hole Excess) | N_L = M_L / K_L           | O_L = N_L x L_L          |
|                                        | =.............sk           | =.............gal         |

Displacement = (F x Q)+(B + C + D - A) x I=.............bbl

Notes:
- Excess on open hole volumes= 40% on theoretical calculations or 30% on Caliper
- Excess on cased hole volumes= 10%
- Excess on top of liner= enough to cover 200-300 ft above T.O.L.
6.2 7” Liner Cement Slurry

The cement slurry for 7” liner will be designed based on Bottom Hole Static Temperature (BHST) as follow:

Table 6-21: 7” liner cement slurry composition and properties

<table>
<thead>
<tr>
<th>DHST (F)</th>
<th>Slurry</th>
<th>Weight (pcf)</th>
<th>Thickening Time (Hrs)</th>
<th>Compressive Strength</th>
</tr>
</thead>
<tbody>
<tr>
<td>BHST&lt;250</td>
<td>“G” Neat Cement</td>
<td>108 - 125</td>
<td>≈ 4.5</td>
<td></td>
</tr>
<tr>
<td>BHST&gt;250&lt;300</td>
<td>“G” + 35% S.F or Flexstone or Cemcrete</td>
<td>108 - 125</td>
<td>≈ 4.5</td>
<td>± 4000 psi @ 225 Deg F</td>
</tr>
<tr>
<td>BHST &gt;300</td>
<td>“G” + 35% S.F or Cemcrete</td>
<td>108 - 125</td>
<td>≈ 4.5</td>
<td></td>
</tr>
</tbody>
</table>

Notes:
- Excess on open hole volumes= (40 – 70)% on theoretical calculations or 35% on Caliper
- Excess on cased hole volumes= 10%
- Excess on top of liner = enough to cover 200 ft above T.O.L.

For detailed cementing procedure refer to the relevant Section in Chapter-2 “Drilling Operations Guidelines” of this Volume.

7. Evaluation of Primary Cement

The cement job can be evaluated as follow:

- Hydraulic testing
- Acoustic
  - Sonic (CBL/VDL, CBT): omni-directional
  - Ultrasonic (USI, SBT): high resolution image
- Based on comparison between CQPs and the needed requirements.

7.1 Hydraulic Testing

These kinds of tests primarily testing the isolation provided by the cement.

Several techniques are used to evaluate the degree of isolation provided by the cement.
7.1.1 Pressure Testing (Shoe Bond Test)

Shoe Bond Test is the most common test. It is generally performed after every surface or intermediate cement job, once casing shoe has been drilled. The internal casing pressure is increased until the pressure at the casing shoe becomes larger than the expected to be applied at this point during drilling the next phase (normally 0.65 lb/ft). If the casing shoe did not hold the pressure indicates poor cement job, and remedial cementing is required.

7.1.2 Dry Testing

Dry tests are particularly useful to test the effectiveness of a cement squeeze or a cement seal at the top of liner. The objective of the dry test is to prove that when the pressure reduced inside the casing, nothing is coming into the wellbore.

7.1.3 Tests Through Perforations

When cement bond logs show poor results, or when effective isolation is required over short intervals, the casing is perforated in two different locations. A packer is set between the two perforation sets and communication test to be carried out between the two perforations.

7.2 Temperature, Nuclear (Cement Top)

Cement generates a considerable heat due to the exothermic reaction while setting. This heat reaction increases the temperature of the fluid inside the casing which can be measured by a temperature survey. The fluid in the casing should be left undisturbed following completion of the cementation until the survey is made.

7.3 Acoustic

7.3.1 CBL/VDL Log

In order to have reliable CBL/VDL the following conditions are essential.

- Casing sizes preferably 9 5/8" or less.
- Good tool centralization, at least 3 centralizers must be used
- The transmitter and receiver must be within 1/8" of the pipe centre. The centralisers must be close fitting ±1/8" of pipe internal diameter.
- At least one of the centralisers must be mounted within one foot from the sonic transmitter receiver pair.
On deviated wells the CBL/VDL must be centralized and run specifically across each casing string separately, i.e the tool should be centralized for 7" liner and logged across the liner. New centralisers must be installed to log the 9 ⅝" casing (if required).

On vertical wells, it is possible to obtain a reasonable log across both 7" and 9 ⅝" casings in one run provided the stronger spring centralisers are used.

7.3.2 USI Log

- The USI evaluates cement with an ultrasonic transducer operating between 200 and 700 kHz.
- Full casing coverage at 1.2 inch (30 mm) resolution using rotating transducer.
- Measurements.
  - Cement evaluation
  - Casing Corrosion and wear

7.3.3 Factors Affecting USI Response

- Casing shape and rugosity.
  - Normal manufacturing pattern affect cement image slightly
  - Wear, corrosion and extreme manufacturing patterns create affects that can be diagnosed by correlations with casing images.
- Tool accenting.
- Third interface reflections (outer casing or hard formation).

Following are logs illustrate problems of cementing and show the differences between good cement and poor cement on logs.
7.3.4 Poor Cement

Figure 6-6: Log illustrates poor cement
7.3.5 Mud Channels and Contaminated Cement

Figure 6-7: Log illustrates contaminated cement and mud channels
7.3.6 Good Cement

Cement bond logs of production casings can be cancelled if ALL Cement Quality Parameters (CQP’s) are met.

This only applies to ADCO oil producer wells and must be approved both by PDD and DD through filling and signing the Cementing Evaluation Report (CER-Form#1).

- DS of concerned rig to fax the completed form (available in public folder in Drilling / Departments / HDO(Bu/Bb) / Mud & Cement/ Forms) after the liner job to concerned SOE.

- SOE of concerned rig and SCE to review, finalize and sign the form. Relevant documents to be attached with the form.

Figure 6-8: Log illustrates good cement

7.4 Cement Bond Logs Rationalization

Cement bond logs of production casings can be cancelled if ALL Cement Quality Parameters (CQP’s) are met.

This only applies to ADCO oil producer wells and must be approved both by PDD and DD through filling and signing the Cementing Evaluation Report (CER-Form#1).

- DS of concerned rig to fax the completed form (available in public folder in Drilling / Departments / HDO(Bu/Bb) / Mud & Cement/ Forms) after the liner job to concerned SOE.

- SOE of concerned rig and SCE to review, finalize and sign the form. Relevant documents to be attached with the form.
• SOE to approach PDD for approval.

• PDD to sign and return the form to SOE and SCE.

• Original of the form to be kept with SCE, one copy to be kept in well file (by SOE) and one copy to be kept by PDD (SPE).

**Note:**

SCE to act as custodian and ensure that forms are prepared, signed by all parties and filed for every concerned job. Also SCE to keep all forms in a dedicated folder for further analysis/reference.

The process must be strictly adhered to and logs can only be cancelled after full evaluation of the CQP's and the relevant form signed by both DD and PDD.

**Important:**

If any doubt on the cementing operation, log must be run!