1.0 **GENERAL WELL CONTROL POLICIES**

1 **SCOPE**

It is the policy of Romfor International Ltd that all employees and contractors comply with all well control policies, procedures, and rules presented in this manual in all circumstances where they apply. Romfor’s main objective is to maintain a safe and efficient drilling operation; therefore, the rules in this manual define the minimum level for well control on all rigs.

The purpose of this document is to enhance individual, operator, contractor, and service provider well control response by establishing a baseline standard of safe and effective drilling operations for Romfor personnel to follow.

2 **INTERPRETATION**

The policies, rules, and practices identified in this manual shall be interpreted to bring about maximum compliance and safe work practices and shall take precedence over any conflicting instructions, except for applicable governmental regulations that may be contrary to these rules. In this case, governmental regulations shall supersede Romfor’s regulations.

3 **KNOWLEDGE**

Each Romfor employee involved in or responsible for well control operations shall have access to this manual and know, understand, and comply with the requirements that apply to his or her work.

4 **DEVIATION FROM PROCEDURES**

The Sr. VP, COO and the Division Operations Manager shall approve in writing any deviations from the well control policies and procedures detailed in this manual.

5 **PRE OPERATIONS PLANNING (PRE-SPUD)**

The PIC shall ensure that before starting operations on any well or major activity, a meeting of all parties involved (pre-spud meeting) occurs. The purpose of this meeting is to review and agree to the policies and procedures for both routine and non-routine operations. Where parties have differences in policy and procedures, mutually acceptable operations shall be agreed to, and any perceived area of well control procedure conflict shall be resolved before beginning the operation.
6 GOVERNMENTAL SAFETY STANDARDS

In addition to its own safety standards, rules, and policies, Romfor and its employees are subject to regulations of various governmental and jurisdictional agencies in the countries where Romfor facilities operate. Management and supervision must make sure that all applicable provisions of the governmental regulations are complied with and that the Division Operations Manager and rig employees are made aware of these requirements where they differ from the requirements identified in this and other Romfor documentation.

7 REVISIONS TO THE WELL CONTROL MANUAL

Revisions or amendments to these policies and rules shall only be made in accordance with the policies and procedures established by Romfor.

At least one trip drill, pit drill, or other well control drill shall be carried out daily as conditions permit and at the discretion of the PIC and the Operator’s Representative. All drills will be performed in accordance with the procedures in this manual and the PIC will record them on the drill report.

Specific drills to be carried out include:

- Kick while tripping
- Kick while drilling
- Instructions to divert

Other drills may include:

- Full BOP drills
- Stripping drills

9 TERMINATION OF DRILLING OPERATIONS

Drilling operations will be terminated if any of the following conditions exist:

- Weather conditions exceed the limits established for each rig and various operations.
- A stack, kill and choke lines, manifold, or choke fails to hold test pressure.
- There is any indication of leakage from a slip joint or any part of a riser.
- There is pressure loss in the mud system.
- If the drilling fluid becomes gas cut to the point of creating a fire hazard in the rotary area of the drill floor. In this case, workers must stop drilling and close the diverter or annular until the hazard is eliminated.
• The PIC or Rig Manager feels that the safety of personnel, environment, or property may be in jeopardy.

10 UNDER BALANCED DRILLING

It is Romfor’s policy that under balanced drilling operations conducted as part of the well plan require prior written approval of the President, Vice-president and the Division General Manager.

11 TRAINING

The Division Manager shall ensure that the following personnel within their respective organizations attend a Romfor-approved well control training program at least once every 24 months or as required by local regulations:

• PIC
• Toolpushers, Tourpushers
• Drillers
• Assistant Drillers
• Rig Managers and Drilling Superintendents
• Floormen
• Derrickmen

12 RECORD KEEPING AND REPORTING

During all phases of the drilling operation, the PIC shall ensure that accurate records are maintained according to Romfor policies and procedures. The Well Control Worksheet is used to record and report well information when a kick/blowout occurs and must be kept in an accessible location.

The following information shall be known before the start of operations:

• Maximum allowable annular surface pressure (MAASP)
• Casing burst pressure

The Driller will keep an approved kill sheet up to date during the operation with the information above, plus depth, pipe volumes, and mud weight.

13 CLARIFYING DOCUMENTS
As necessary, additional information and instructions clarifying the policy and/or procedures may be issued through bulletins, operating and maintenance instructions, safety alerts, and other means to supplement the rules, guides, and procedures identified in this manual. Supervisory personnel shall make these supplements available to all affected employees.
2.0 GENERAL WELL CONTROL RULES

Applicability
These requirements are applicable to all Romfor rig operations.

Rules Applicable to All Rig Types:

1 FLOW CHECKS

DRILLING FLOW CHECKS

Drilling flow checks shall be made:

- At all drilling breaks and when changes occur in drilling speed, or in direction (up/down)
- At changes in flow rates
- At an increase in pit levels
- When reduction in mud weight occurs after circulation
- When deemed necessary by the Driller or Rig Manager

TRIPPING FLOW CHECK

Trip flow checks shall be made:

- When the drill bit is just off the bottom
- Before pumping a slug
- When the drill collars reach the casing shoe
- When the drill collars reach the blowout preventer (BOP)
- When mud weight changes
- When deemed necessary by the Driller or Rig Manager

SAFETY VALVES

A minimum of one full opening safety valve (FOSV) held in the open position with appropriate crossovers (or circulating head for casing) and operating handle will be available on the drill floor at all times.

Any time a trip is interrupted, a full operating safety valve will be installed (hand tight). The Driller is responsible for testing of the safety valve.

3 DEPTHS
The Driller shall at all times be aware of the distance from the rig floor to the pipe rams and this data shall be posted on the drill floor.

The Driller shall be aware of the well true vertical depth and measured depth.

4 Valve Line Up

The Driller at the start of each tour is responsible for ensuring that the choke manifold, diverter, and dump valves are lined up correctly for the operation being conducted.

5 Blowout Preventer Test (BOP)

The Toolpusher or Rig Manager shall ensure that BOP tests are conducted when the BOP is initially installed and then at a minimum weekly thereafter. The maximum interval between tests is 14 days if approved by the PIC. In this case, functional tests shall be carried out weekly. Tests shall also be conducted when pressure seals are broken, before drilling into known abnormally high-pressure formations, and after each string of casing. All testing of the BOP and related equipment shall be in accordance with local regulations.

Test the BOP on a test stump with a test pump. Do not use the cementing unit without prior approval of the PIC. Pressure readings when testing on the test stump shall be recorded using a recording type pressure gauge.

When a multiplex (mux) BOP system is equipped with a deadman switch, the system shall be kept operational unless the Operator’s Representative has requested in writing that it be disarmed. The position of the deadman shall be recorded on the IADC report and signed by the PIC and the Operator’s Representative once the stack is landed and any time the position is changed.

6 General Well Control Procedure

When drilling operations are being conducted using a surface BOP, the “weight and wait” method to kill the well should be used. Offshore operations using sub-sea BOP’s, the “driller’s” method is preferred. Which method to use shall be decided before spud by a joint meeting of the operator and Romfor and the information forwarded in writing to the rig.

The top drive or kelly shall always be used for well control operation. A kick assembly shall be installed as an alternative when a kick is likely to exceed the rated working pressure of the top drive.

When the string is off bottom or out of the hole, the first consideration should be to safely return the bit to bottom. The recommended method is to install a non-return valve in the string and strip through the annular preventer.
7 PUMP CIRCULATION

Slow circulation rates shall be used at a minimum of once each tour. Slow circulation rates (SCR) shall also be used during the following conditions:

- When mud weight changes by +/- 0.2 ppg.
- When the string length increases by 300 feet or more in zones below spud depth.
- When output of the pump changes.
- When a bit or BHA has been changed (mud should be conditioned first).

After closing an annular on a suspected influx with no pressure showing on the drill pipe or casing, take precautions that assume there is an influx. Keep the annular closed and circulate bottoms up through the choke line, kill line, or both.

On offshore facilities, when circulating bottoms up through a riser, after trips, wiper trips, and drilling breaks, be aware that there may be a sudden increase in flow rate. The Driller must be prepared to handle the flow surge of mud and gas by checking the slip-joint pack-off pressure and having the drill pipe in position for closing an annular preventer. A designated crew member shall also be assigned to the BOP control console and be ready to divert overboard if required. When a flow surge is detected, divert and close the designated annular preventer.

8 REMOVAL OF BOP

The BOP shall not be removed until the well has been properly plugged or secured.

9 USE OF FLOATS

A solid float shall be used while drilling and hole opening before setting the surface casing. When a float is used in other circumstances, a ported float is acceptable.

10 WELL CONTROL MATERIALS

The following well control materials shall be maintained on the rig at all times:

- Sufficient weight control material to increase the weight of the active mud system by 1 ppg or the amount stipulated on the approved drilling permit, whichever is greater or,
- 1000 sacks barite
- 200 sacks gel
- Sufficient cement to allow a 400-foot plug to be set.

The PIC shall suspend drilling operations any time these materials are not available, and shall not resume drilling until they have been delivered to the facility.
11 TRIPPING

During all trips or when the pipe is out of the hole, the hole shall be kept full of mud using the trip tank or stroke counter.

Tripping out of the hole with losses of mud is permitted only where the formation conditions are known and approval has been obtained from the Rig Manager.

12 WELL SHUT IN

When a well is to be shut in, use the “hard shut-in” method (where the remote choke remains closed during drilling).

13 OIL-BASED DRILLING MUD GAS SOLUBILITY

When an oil-based or synthetic-based mud is being used and there is a possibility of gas going into solution, which may mask an influx, circulation through a choke shall be considered.

14 KICKS OFF BOTTOM

When the string is off bottom or out of the hole, the first consideration should be to return the bit safely to bottom. The recommended method is to install a non-return valve in the string and strip through the annular preventer.

STRIPPING

When stripping, adhere to the following:

- Install a non-return valve (NRV) above the full opening safety valve.
- Open the FOSV and check the NRV is not leaking prior to stripping.
- Make sure spare FOSV and handle assembly is available on the rig floor.
- Remove all drillpipe/casing protectors.
- Check that annular operating pressure is as low as possible to avoid leakage.
- Monitor flowlines for leakage.
- Ensure tool joints are smooth and free from burrs.
- Fill each stand; measure and record volumes.
- Accurately measure mud volumes bled off into trip tank. If equipped, use a stripping tank.
- Plot casing pressure for each stand to identify when the string enters the flux.
• Adjust the annular regulator to maintain the correct closing pressure. Allow fluid to vent slightly as each tool joint passes through the annular.

• Have a surge bottle, if available, connected to the annular closing line.

• Restrict stripping speeds to less than 2 feet per second.

**OFF BOTTOM KILL**

An off bottom kill involves circulation with the bit other than on bottom. This might be considered if the following occur:

• Casing pressure is too high to strip.

• Pipe is stuck.

• Equipment problems occur.

• Excessive heave occurs.

• The kill mud is based on the actual shut in pressures relative to the bit TVD rather than hole measured depth.

Note that this method poses considerable risks.

**STRING OUT OF HOLE**

If the string is out of hole when the well is shut in and stripping is required, it is first necessary to check if pressure will allow stripping to commence.

If stripping is feasible, start with drillpipe or slick drill collars. It may be necessary to use the top drive or kelly to increase the weight.

• Install non-return valve on the first stand. Use bit with no nozzles.

• Lower the stand until just above the blind shear rams.

• Close annular.

• Open blind shear rams.

• Follow normal annular stripping procedure.

**15 SHALLOW GAS PROCEDURE – GENERAL**

When a rig is operating in a location where shallow gas is suspected or cannot be ruled out, the following shall be adhered to:

• A spud meeting will be held by the PIC and Operator's Representative to evaluate the risk of shallow gas, taking into account the depth of suspect zones and other known or
suspected conditions, and determine if the well shall be given to spud only during daylight hours.

- Personnel shall be assigned to monitor for gas bubbles and inform the Toolpusher immediately if bubbles are observed.
- A pilot hole no larger than 8 ½” in diameter shall be drilled to a maximum depth of 400 feet.

16 **RISER, CHOKE, AND KILL LINES – GENERAL**

Choke line friction shall be measured as soon as the BOP is installed and each time there is a change in mud properties of +/- 0.2 ppg.

The choke and kill lines shall be kept full of weighted drill mud. The lines shall be circulated with new mud at a minimum of once every 24 hours. Where gelling of the mud is an issue, the lines shall be circulated more often as the Driller thinks necessary. In depths greater than 2000 feet, circulate kill weight mud prior to opening the well.

17 **PILOT HOLE – GENERAL**

When drilling out a pilot hole the following requirements shall be adhered to:

- The maximum depth of the pilot hole shall be 400 feet.
- Adequate kill mud shall be available and ready to use in the pits.
- A Job Safety Analysis (JSA) shall be conducted per Romfor procedures before drilling the pilot hole.

18 **ROTATION OF THE DRILL STRING – GENERAL**

The drill string shall not be rotated in the BOP if the wellhead angle exceeds 1 degree, or a written variance has been approved by the Drilling Superintendent.
3.0 PROCEDURES

Primary Well Control
Formation Tests
Secondary Well Control – Diverting While Drilling
Secondary Well Control – Diverting While Tripping
Secondary Well Control – Hard Shut-In (Surface BOP) - Drilling
Secondary Well Control – Hard Shut-In (Surface BOP) - Tripping
Well Control Procedure – Driller Method
Well Control Procedure – Wait and Weight Method
Well Control Procedure – Volumetric Method
Well Control Drill Procedure – Kick While Tripping
Well Control Drill Procedure – Kick While Drilling
Relief Well Drilling Procedures
PRIMARY WELL CONTROL

PURPOSE

The purpose of this procedure is to define the primary methods for well control on Romfor International Ltd facilities.

SCOPE

This procedure applies to all Romfor land and offshore rigs.

GENERAL

The policy of Romfor is that under balanced drilling requires prior notification of the SR. VP & COO and Division General Manager. The requirements established in this procedure are based on this policy. If under balanced drilling is part of the well plan, specific procedures shall be established prior to the drilling operations.

The primary method of well control is to ensure that the correct density of drilling fluid is maintained. The hydrostatic pressure exerted by the drilling fluid should be sufficient to prevent influx of formation fluid into the wellbore, but less than the pressure that will fracture the formation.

RESPONSIBILITIES

The Division General Manager is responsible for the administration, interpretation, and maintenance of this document.
BACKGROUND

CAUSES OF KICKS

There are several causes of kicks, including any of the following:

- **Abnormal Formation Pressure**
  Drilling into a formation that has a higher than expected formation pressure can result in the well starting to flow and the potential of a kick.

- **Insufficient Mud Weight**
  The primary method of controlling kicks is to ensure that the weight of the drilling fluid (mud) is sufficient to exert a hydrostatic pressure sufficient to prevent influx of the formation fluid into the wellbore. This can happen if there is a reduction of the weight of the mud. Loss of mud weight can occur from the following:
  - Dilutions of mud
  - Gas cutting of mud
  - Settling of weighting material in the drilling fluid

- **Failure to Keep the Hole Full of Mud While Tripping**
  As the string is pulled from the hole, the mud level can drop, causing a reduction in hydrostatic pressure and potentially allowing the well to flow.

- **Loss of Circulation**
  Loss of circulation will result in the mud level dropping in the hole, with the resulting reduction in hydrostatic pressure in the hole potentially allowing the hole to flow.

- **Swabbing**
  As the pipe is being pulled from the hole, friction loss can result in a drop of hydrostatic pressure at the bottom of the hole. The primary causes of swabbing are:
  - Excessive pulling speeds
  - Excessive mud viscosity
  - Ballled up bit and bottom hole assembly (BHA)

INDICATION OF ABNORMAL FORMATION PRESSURES

Early detection of abnormal formation pressures requires the monitoring of a combination of trends. An increase in one or more of the following trends may indicate a potential kick. Determination of a potential kick must be evaluated based on the Driller’s experience and evaluation of the data.

- **Increase in Rate of Penetration (Shales)**
When drilling into shale an increase in the rate of penetration (ROP) may indicate formation pressure higher than expected.

- **Increase in Gas Levels**
  
  An increase in background gas levels may indicate an increase in formation pressure and should be investigated. Background gas levels are unreliable for determining a kick, as they change with very minor formation pressure changes. However, the appearance of connection gas does indicate that the formation is very close to the weight of the mud.

- **Increase in Torque and Drag**
  
  As the ratio of the formation pressure to hydrostatic pressure of the mud increases, this may indicate sloughing and heaving of the shales, resulting in an increase in the torque and drag, and may also indicate changes in formation pressure.

- **Change in Cutting Size and Shape**
  
  An increase in formation pressure normally results in an increase in cutting size. As the formation approaches the mud weight, cuttings start to splinter off the bottom of the hole (cavings).

- **Decrease in Shale Density**
  
  Under normal conditions, the density of the shale will increase with depth. As formation pressure increases the shale becomes more porous, resulting in a decrease in density.

- **Change in Mud Chlorides**
  
  If the level of chlorides in the mud system changes without reason, this may indicate a change in porosity, the introduction of formation fluid, and an increase in formation pressure.

- **Change in Mud Temperature**
  
  High formation pressures result in a change in the normal temperature gradient of the formation. This may be seen as a change in the normal trend of mud temperature.

**DETECTION OF AN INFLUX**

The following operational changes indicate the influx of formation fluids:

- **During Drilling Operations**
  
  - An increase in the return flows
  - An increase in the levels in the mud pits
  - A decrease in pump pressure and/or pump stroke
Drilling brakes

• **During Tripping Operations**
  - Hole not taking the required amount of fluid (either running in or pulling out)
  - A positive flow from the wellbore

**PREVENTION**

**TRIPPING**

Follow these procedures on all trips.

• **Mud Conditions**
  Before starting a trip, a full bottoms up should be circulated and the following criteria must be met:
  - No indications of mud loss should be present.
  - No indication of an influx of formation fluids should occur.
  - Mud weight in and out should not vary by more than +/- 0.2 ppg.

• **Trip Sheet**
  The Driller will prepare a trip sheet and use it during all trip operations.

• **Trip Tank**
  The Driller will ensure the trip tank is full and functional before removing the top drive.

• **Safety Valve**
  Ensure appropriate safety valves and/or crossovers (for each pipe size) are on the drill floor with closing tool and ready for immediate use.

• **Pumping Out of the Hole**
  When pumping out of the hole, the Driller must closely monitor the volume of the mud in and out.

• **Slugs**
  When not pumping out of the hole a slug will, where possible, be pumped into the string. The Driller must ensure that the returns from the slug are correct before beginning the trip.

• **Mud Bucket**
  Use a mud bucket when the pipe is to be pulled wet and direct returns into the trip tank.

**PULLING OUT OF THE HOLE**
Follow these procedures when pulling out of the hole.

- **Incorrect Hole Fill**
  If the hole is not taking the correct amount of drilling fluid, make a flow check.
  - Well flowing – Shut in
  - Well static – Normally run back to bottom and circulate bottoms up

- **Flow Checks**
  At a minimum, make flow checks before beginning a trip, at the casing shoe, and the BHA entering the stack.
  The flow check should be long enough to ensure that the well is not flowing.

- **Filling the Trip Tank**
  Stop pipe movement while the trip tank is being filled.

- **Break in Tripping**
  Install a safety valve whenever tripping is stopped.

- **Pulling Speed**
  Pull pipe at a slow speed to prevent swabbing.

**RUNNING INTO THE HOLE**

Follow these procedures when running into the hole.

- **Trip Tank**
  Closely monitor the trip level, taking into account that displacement is affected by floats, either solid or ported, and by bit and nozzle size.

- **Breaking Circulation**
  Break circulation at the shoe.

- **Bottoms Up Circulation**
  - When circulating bottoms up, closely monitor mud volumes.
  - Keep transfers and mixing to a minimum.

- **Float in String**
  When a float is installed in the string, fill the drillpipe at least every 15 stands.

**DRILLING**

During drilling operations, make flow checks when the following conditions occur, and monitor the well for enough time to ensure that formation fluids are not flowing.
Drilling breaks, either positive or negative
- Change in return flow
- Unexplained increase in pit levels
- Note: The Mudman must remain in constant communication with the Driller.
- Changes in pump pressure and stroke

**FORMATION TESTS**

**PURPOSE**

The purpose of this procedure is to define the primary methods for performing formation integrity tests on Romfor rigs.

**SCOPE**

This procedure applies to all Romfor rigs.

**GENERAL**

It is the policy of Romfor that prior to a spud in a formation test shall be conducted just below the shoe before drilling a new section. The test is designed to test the strength of the formation.

There are two common tests used, the formation integrity test (FIT) and the leak off test (LOT). The classification of the well and the amount of knowledge about the formation determines which test to use.

**RESPONSIBILITIES**

The Division General Manager is responsible for the administration, interpretation, and maintenance of this document.
BACKGROUND

When conducting either test, adhere to the following:

- Drill out the shoe, rat hole, and at least 10 feet of new formation.
- Circulate and condition the drilling fluid to ensure uniform mud weight.
- Pull back into the shoe.

Use a high pressure, low volume pump such as the cement pump. Rig pumps are not suitable for this test.

FORMATION INTEGRITY TEST

The FIT applies a pressure to the well equal to a predetermined equivalent mud weight. The test is also known as an equivalent mud weight test.

The test does not fracture or break down the formation. A FIT test is acceptable on a development well where formation pressures in the hole section are not known with confidence. It is not appropriate for exploration wells.

LEAK OFF TEST

The objective of a leak off test is to measure the pressure required to force drilling fluid (mud) into the formation (formation intake pressure).

Mud is pumped slowly into the closed wellbore until the pressure ceases to increase linearly indicating that mud is being forced into the formation.

From the surface pressure being applied, the following is calculated:

- Maximum allowable mud weight
- Maximum allowable annular surface pressures

Continuing to pump mud after the pressure deviates from a straight line can fracture the formation, reducing the strength of the formation.

A leak off test is normal in an exploration well and where formation strengths are uncertain.
SECONDARY WELL CONTROL – DIVERTING WHILE DRILLING

PURPOSE

The purpose of this procedure is to define when gas will be diverted while drilling.

SCOPE

This procedure applies to all Romfor rigs. Shallow gas is any gas encountered at a depth before setting the first string of competent casing (i.e., designed to hold pressure with a BOP stack).

GENERAL

Diverting shall be considered as secondary control. When instructions are issued to divert, heavy mud should be available in the reserve pit. Adequate water supplies shall be maintained and ready for use.

RESPONSIBILITIES

The Division General Manager is responsible for the administration, interpretation, and maintenance of this document.
<table>
<thead>
<tr>
<th>Step #</th>
<th>Process Step</th>
<th>Description</th>
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</table>
| 1      | Keep Toolpusher/PIC Advised On Formation Conditions | Operator’s Representative:  
- Keep the Toolpusher/PIC advised on formation and local conditions during drilling operations. |
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| 2 | Indication Well Flowing | Toolpusher/PIC:  
- Receive notification that the well is flowing. |
| 3 | Stop Drilling And Continue Pumping | Toolpusher/PIC:  
- Direct Driller/Assistant Driller to stop drilling.  
- Direct Mudman/Derrickman to continue pumping. |
| 4 | Open Diverter Vent Line | Toolpusher/PIC:  
- Direct diverter vent line to be opened. |
| 5 | Close Flowline To Shaker | Toolpusher/PIC:  
- Direct that flowline to shaker be closed. |
| 6 | Close Diverter | Toolpusher/PIC:  
- Direct diverter to be closed. |
| 7 | Raise Alarm | Toolpusher/PIC:  
- Announce well control emergency condition on the intercom system.  
- Non-essential personnel muster at stations. |
| 8 | Increase Pump Stroke To Maximum | Driller/Assistant Driller:  
- Direct that mud pumps stroke be increased to maximum. |
| 9 | Switch To Heavy Mud | Driller/Assistant Driller and Mudman/Derrickman:  
- Switch to the heavy mud in the reserve pit. |
| 10 | Is Well Still Flowing? | Toolpusher/PIC:  
- Determine if heavy mud has killed flow.  
  - If yes, go to Step 12, “Continue To Pump.”  
  - If no, go to Step 11, “Stop Pumps’ Flow And Check Well.” |
| 11 | Stop Pumps’ Flow And Check Well | Driller/Assistant Driller:  
- Stop pumps.  
- Flow check well to verify kick has been killed. |
| 12 | Continue To Pump | Driller/Assistant Driller:  
- Continue to pump all remaining mud available.  
- Line up to pump water.  
- Pump water after all available mud has been used as long as well continues to flow. |
SECONDARY WELL CONTROL – DIVERTING WHILE TRIPPING

PURPOSE

The purpose of this procedure is to define secondary well control procedures, the correct use of the blow out preventer (BOP) equipment to control a well when primary well control is lost, and the constant bottom hole pressure methods to regain primary control.

SCOPE

This procedure applies to all Romfor rigs.

GENERAL

Early recognition and rapid shut-in of the well are key to effective well control. Faster shut-in results in:

- Smaller kicks
- Lower shut in pressure
- Less risk of breaking down the formation

Romfor policy is to use the “hard” shut-in method.

RESPONSIBILITIES

The Division General Manager is responsible for the administration and maintenance of this procedure.
Toolpusher/PIC

1. Keep Toolpusher/PIC Advised On Formation Conditions

2. Indication Well Flowing

3. Set Slips

4. Open Diverter Vent Line

5. Close Flowline To Shaker

6. Close Diverter

7. Raise Alarm

8. Increase Pump Stroke To Maximum

9. Switch To Heavy Mud

10. Well Still Flowing?

11. Stop Pumps' Flow And Check Well

12. Continue To Pump

Driller/Assistant Driller

Mudman/Derrickman

Sub-Sea Engineer

Operator's Representative
<table>
<thead>
<tr>
<th>Step #</th>
<th>Process Step</th>
<th>Description</th>
</tr>
</thead>
</table>
| 1      | Keep Toolpusher/PIC Advised On Formation Conditions | Operator’s Representative:  
• Keep Toolpusher/PIC advised on formation and local conditions during tripping operations. |
| 2      | Indication Well Flowing              | Toolpusher/PIC:  
• Receive notification that the well is flowing. |
| 3      | Set Slips                            | Toolpusher/PIC:  
• Direct Driller to stop trip.  
• Direct Mudman/Derrickman to continue pumping. |
| 4      | Open Diverter Vent Line              | Toolpusher/PIC:  
• Direct diverter vent line to be opened. |
| 5      | Close Flowline To Shaker             | Toolpusher/PIC:  
• Direct that flowline to shaker be closed. |
| 6      | Close Diverter                       | Toolpusher/PIC:  
• Direct diverter to be closed. |
| 7      | Raise Alarm                          | Toolpusher/PIC:  
• Announce an emergency on the intercom system.  
• Non-essential personnel muster at stations. |
| 8      | Increase Pump Stoke To Maximum       | Driller/Assistant Driller:  
• Direct that mud pumps stroke be increased to maximum. |
| 9      | Switch To Heavy Mud                  | Driller/Assistant Driller and Mudman/Derrickman:  
• Switch to the heavy mud in the reserve pit. |
| 10     | Well Still Flowing?                  | Toolpusher/PIC:  
• Determine if heavy mud has killed flow.  
  − If yes, go to Step 12, “Continue To Pump.”  
  − If no, go to Step 11, “Stop Pumps’ Flow And Check Well.” |
| 11     | Stop Pumps’ Flow And Check Well      | Driller/Assistant Driller:  
• Stop pumps.  
• Flow check well to verify kick has been killed. |
| 12     | Continue To Pump                     | Driller/Assistant Driller:  
• Continue to pump all remaining mud available.  
• Line up to pump water.  
• Pump water after all available mud has been used as long as well continues to flow. |
SECONDARY WELL CONTROL – HARD SHUT-IN (SURFACE BOP) - DRILLING

PURPOSE
The purpose of this procedure is to define secondary well control procedures, the correct use of the blow out preventer (BOP) equipment to control a well when primary well control is lost, and the constant bottom hole pressure methods to regain primary control.

SCOPE
This procedure applies to all Romfor rigs.

GENERAL
Early recognition and rapid shut-in of the well are key to effective well control. Faster shut-in results in:

- Smaller kicks
- Lower shut in pressure
- Less risk of breaking down the formation

Romfor policy is to use the “hard” shut-in method.

responsibilities
The Division General Manager is responsible for the administration, interpretation, and maintenance of this document.
Toolpusher/PIC

Stop Drilling

2

Driller/Assistant Driller

Stop Mud Pumps’ Flow And Check Well

3

Is Well Flowing?

No

4

Yes

Mudman/Derrickman

Resume Drilling

9

Sub-Sea Engineer

Record Conditions And Make Report

8

Operator’s Representative

Keep Toolpusher/PIC Advised On Formation Conditions

1

Close BOP

5

Is Well Shut In?

No

7

Yes
<table>
<thead>
<tr>
<th>Step #</th>
<th>Process Step</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Keep Toolpusher/PIC Advised On Formation Conditions</td>
<td>Operator’s Representative:</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Keep the Toolpusher/PIC advised on formation and local conditions during drilling operations.</td>
</tr>
<tr>
<td>2</td>
<td>Stop Drilling</td>
<td>Toolpusher/PIC:</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Direct that the drilling be stopped.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Pick up drill string and space out for shut-in of well.</td>
</tr>
<tr>
<td>3</td>
<td>Stop Mud Pumps’ Flow And Check Well</td>
<td>Driller/Assistant Driller and Mudman/Derrickman:</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Stop circulation of drilling fluid.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Flow check well.</td>
</tr>
<tr>
<td>4</td>
<td>Is Well Flowing?</td>
<td>Driller/Assistant Driller:</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Based on flow check, determine if well is flowing.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>− If yes, go to Step 5 “Close BOP.”</td>
</tr>
<tr>
<td></td>
<td></td>
<td>− If no, go to Step 9 “Resume Drilling.”</td>
</tr>
<tr>
<td>5</td>
<td>Close BOP</td>
<td>Driller/Assistant Driller:</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Close BOP.</td>
</tr>
<tr>
<td>6</td>
<td>Open Choke Line Valve (HCR)</td>
<td>Driller/Assistant Driller:</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Open the choke line valve (HCR).</td>
</tr>
<tr>
<td>7</td>
<td>Is Well Shut In?</td>
<td>Driller/Assistant Driller:</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Verify that well is shut in.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>− If yes, go to Step 8 “Record Conditions And Make Report.”</td>
</tr>
<tr>
<td></td>
<td></td>
<td>− If no, return to Step 5 “Close BOP.”</td>
</tr>
<tr>
<td>8</td>
<td>Record Conditions And Make Report</td>
<td>Driller/Assistant Driller:</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Record shut-in drill pipe pressure (SIDPP).</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Record shut-in casing pressure (SICP).</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Record pit gain.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Notify Toolpusher/PIC.</td>
</tr>
<tr>
<td>9</td>
<td>Resume Drilling</td>
<td>Toolpusher/PIC:</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Resume drilling.</td>
</tr>
</tbody>
</table>
WELL CONTROL PROCEDURE – DRILLER METHOD

PURPOSE

The purpose of this procedure is to define the Driller’s method of well control.

SCOPE

This procedure applies to all Romfor rigs.

GENERAL

Specific considerations:

- Kill mud shall be exactly the right weight (no safety margin, trip margin, etc., until later).
- Follow correct startup procedure.
- Surface BOP shall hold casing pressure constant.
- Line volumes (from pump to top drive) must be taken into account.
- Prepare and use a Romfor kill sheet.
- Accurate records of all events shall be kept by a nominated person.
- Before opening BOP, the well shall be flow checked via the choke.

RESPONSIBILITIES

The Division General Manager is responsible for the administration, interpretation, and maintenance of this document.
Influx To Wellbore Observed

1. First Circulation Brings Mud Pumps To Kill Speed
2. Monitor Drill Pipe Pressure
3. Hold Drill Pipe Pressure Constant Until Influx Removed From Wellbore
4. Shut Mud Pumps Down
5. Secondary Circulation Brings Pumps To Kill Speed
6. Monitor Drill Pipe Pressure
7. Drill Mud At Bit?
8. No
9. Shut Mud Pumps Down
10. Yes
   - Allow SICP To Increase To Amount Equal To CLF
<table>
<thead>
<tr>
<th>Step #</th>
<th>Process Step</th>
<th>Description</th>
</tr>
</thead>
</table>
| 1     | Influx To Wellbore Observed               | Toolpusher/PIC:  
• Observe influx to Wellbore.                                                                                                             |
| 2     | First Circulation Brings Mud Pumps To Kill Speed | Driller/Assistant Driller and Mudman/Derrickman:  
• Bring mud pumps to kill speed.  
• Open choke.  
• Allow shut-in casing pressure (SICP) to fall by amount equal to choke line friction (CLF).  
   Note: Shut in drill pipe pressure (SIDPP) and SICP should be the same as the original SDIPP. |
| 3     | Monitor Drill Pipe Pressure               | Driller/Assistant Driller:  
• Once kill rate is established, monitor drill pipe pressure.                                                                                   |
| 4     | Hold Drill Pipe Pressure Constant Until Influx Removed From Wellbore | Driller/Assistant Driller:  
• Hold drill pipe pressure constant until influx is removed from the wellbore through circulation.                                               |
| 5     | Shut Mud Pumps Down                       | Driller/Assistant Driller and Mudman/Derrickman:  
• Shut mud pumps down.                                                                                                                           |
| 6     | Secondary Circulation Brings Pumps To Kill Speed | Driller/Assistant Driller and Mudman/Derrickman:  
• Reset stroke counter.  
• Switch circulation to kill weight mud.  
• Bring pumps to kill speed.  
• Allow SICP to fall by amount equal to CLF.                                                                                                     |
| 7     | Monitor Drill Pipe Pressure               | Driller/Assistant Driller:  
• Establish kill rate.  
• Monitor drill pipe pressure.  
• Follow schedule as kill mud is pumped to bit and drill pipe pressure drops from initial circulating pressure (ICP) to final circulating pressure (FCP). |
| 8     | Drill Mud At Bit?                         | Driller/Assistant Driller:  
• Drill mud at bit?  
  − If yes, go to Step 9, “Shut Mud Pumps Down.”  
  − If no, return to Step 6, “Secondary Circulation Brings Pumps To Kill Speed.”                                                                  |
| 9     | Shut Mud Pumps Down                       | Driller/Assistant Driller:  
• Shut mud pumps down.                                                                                                                                 |
| 10    | Allow SICP To Increase To Amount Equal To CLF | Driller/Assistant Driller:  
• Allow SICP to increase until SICP equals CLF.  
• Monitor pressure.                                                                                                                             |
WELL CONTROL PROCEDURE – WAIT AND WEIGHT METHOD

PURPOSE
The purpose of this procedure is to define the wait and weight method of well control.

SCOPE
This procedure applies to all Romfor rigs.

GENERAL
Specific considerations:

- Kill mud shall be exactly the right weight (no safety margin, trip margin, etc., until later).
- Follow the correct startup procedure.
- Blow out preventer (BOP) shall hold casing pressure constant.
- Surface line volumes (from pump to top drive) must be taken into account.
- Prepare and use a Romfor kill sheet.
- Accurate records of all events shall be kept by a nominated person.
- Before opening BOP, the well shall be flow checked via the choke.

RESPONSIBILITIES
The Division General Manager is responsible for the administration, interpretation, and maintenance of this document.
<table>
<thead>
<tr>
<th>Toolpusher/PIC</th>
<th>Driller/Assistant Driller</th>
<th>Mudman/Derrickman</th>
<th>Sub-Sea Engineer</th>
<th>Operator’s Representative</th>
</tr>
</thead>
<tbody>
<tr>
<td>Influx To Wellbore Observed</td>
<td>Bring Mud Pumps To Kill Speed</td>
<td>Monitor Drill Pipe Pressure</td>
<td>Kill Mud At Bit; Hold FCP Until Kill Mud Reaches Surface</td>
<td>Shut Mud Pumps Down</td>
</tr>
<tr>
<td>Step #</td>
<td>Process Step</td>
<td>Description</td>
<td></td>
<td></td>
</tr>
<tr>
<td>-------</td>
<td>-------------------------------------------</td>
<td>-----------------------------------------------------------------------------</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
| 1     | Influx To Wellbore Observed               | Toolpusher/PIC:  
  - Observe influx to wellbore. |
| 2     | Bring Mud Pumps To Kill Speed             | Driller/Assistant Driller and Mudman/Derrickman:  
  - Bring mud pumps to kill speed.  
  - Open choke.  
  - Allow shut-in casing pressure (SICP) to fall by amount equal to choke line friction (CLF). |
| 3     | Monitor Drill Pipe Pressure               | Driller/Assistant Driller:  
  - Once kill rate is established, monitor drill pipe pressure.  
  - Follow schedule; allow drill pipe pressure to drop from initial circulating pressure (ICP) to final circulating pressure (FCP). |
| 4     | Kill Mud At Bit; Hold FCP Until Kill Mud Reaches Surface | Driller/Assistant Driller:  
  - Hold FCP until kill mud reaches surface. |
| 5     | Shut Mud Pumps Down                       | Driller/Assistant Driller and Mudman/Derrickman:  
  - Shut down pumps.  
  - Allow SICP to increase by amount equal to choke line friction and check pressures. |
WELL CONTROL PROCEDURE – VOLUMETRIC METHOD

PURPOSE

The purpose of this procedure is to define the volumetric method of well control.

SCOPE

This procedure applies to all Romfor rigs.

GENERAL

If in either the short or long term circulation of gas out of the wellbore is not possible, gas migration may occur. This results in increasing shut in drill pipe pressure (SIDPP), shut-in casing pressure (SICP), bottom hole pressure (BHP), and casing shoe pressure.

To maintain a constant BHP, the gas must be allowed to expand as it migrates up the annulus. The method to allow the gas to expand is the volumetric method.

DRILLPIPE COMMUNICATION (I.E., USEABLE SIDPP)

Where such communication exists, use the drill pipe gauge as follows:

- Monitor SIDPP.
- Allow SIDPP to rise by about 100 psi to give a safety factor.
- Allow SIDPP to rise by another 100 psi.
- Bleed mud from choke, allowing SIDPP to drop by 100 psi.
- Repeat until able to circulate or gas reaches surface.
- Do not bleed gas from the well by this method.

NO DRILLPIPE COMMUNICATION

In the case of plugged nozzles or string, string not on bottom or no string in the hole, then only the SICP is available. In this case the following procedure shall be adopted:

- Monitor SICP.
- Allow SICP to increase by 100 psi to give a safety factor.
- Calculate the amount of mud to bleed from the annulus to reduce the hydrostatic pressure by 100 psi.
- Allow SICP to increase a further 100 psi.
- Bleed the calculated volume of mud from the annulus via the choke. This should be done slowly, holding the casing pressure constant. The casing pressure will now increase further as it continues to migrate.
Repeat until gas is at surface.

Once gas is at surface, casing pressure may be reduced as follows:

- Slowly pump a volume of mud into the annulus, which will increase the hydrostatic by 100 psi. A small increase in casing pressure will occur due to pumping into a closed system.
- Allow mud to settle through the gas.
- Bleed off the increase in pressure caused by pumping. (Bleed gas only.)
- Bleed off a pressure equal to the hydrostatic of the mud pumped. (Bleed gas only.)
- If mud comes back, stop and wait for gas to work to surface.
- Repeat until all gas is bled off or SICP has dropped to required level.

RESPONSIBILITIES

The Division General Manager is responsible for the administration, interpretation, and maintenance of this document.
Well Control Drill Procedures – Kick While Tripping

Purpose

The purpose of this procedure is to define the requirements for drills simulating a kick during a tripping operation.

Scope

This procedure applies to all Romfor rigs.

General

Well control drills shall be conducted per the requirements of WCP-10 Under balanced Drilling, with the objective of familiarizing each crew member with their function and the techniques to implement.

Drills shall be conducted as realistically as possible. Where practical, there shall be no difference between the drill and actual procedures. Drills should, however, be conducted at an appropriate time to minimize the risk of stuck pipe or any other situation that might be detrimental to the operation.

Kick While Tripping

The objective of this drill is to familiarize the crew with the shut-in procedure to use for a kick while tripping. The drill should only be made with the bit inside casing.

Upon a signal from the PIC, the Driller is expected to do the following:

• Stop other operations.
• Install full opening safety valve (FOSV).
• Close FOSV.
• Close annular.
• Open HCR or failsafes.
• Check well is shut in.
• Start to record pressures.
• Notify person in charge (PIC).

Drills and their durations shall be recorded on the daily IADC Report and as per Emergency Response requirements.

Once the PIC is satisfied that the rig’s crew can respond to a well control incident that occurs during a trip, then the last five steps may be simulated.
WELL CONTROL DRILL PROCEDURE – KICK WHILE DRILLING

PURPOSE

The purpose of this procedure is to define the requirements for drills simulating a kick during drilling operations.

SCOPE

This procedure applies to all Romfor rigs.

GENERAL

Well control drills shall be conducted per the requirements of Under balanced Drilling, with the objective of familiarizing each crew member with their function and the techniques to implement.

Drills shall be conducted as realistically as possible. Where practical, there shall be no difference between the drill and actual procedures. They should, however, be conducted at an appropriate time to minimize the risk of stuck pipe or any other situation that might be detrimental to the operation.

KICK WHILE DRILLING

The objective of this drill is to familiarize the crew with the shut-in procedure to use for a kick while drilling.

The drill may be conducted with the bit in open hole or cased hole. If the bit is in open hole, the well should not actually be shut in.

Upon a signal from the PIC, or by reacting to a simulated pit gain, the Driller is expected to do the following:

• Detect the pit gain (if done).
• Stop drilling.
• Pick up and space out.
• Shut down the pumps.
• Flow check.
• Close annular.
• Open HCR or failsafes.
• Start to record pressures and pit gain.
• Call person in charge (PIC).

The duration of the drill shall be recorded on the daily IADC Report.
With the bit in the open hole, the last four steps should be simulated. Once the bit is in the casing, the top drive can be made up and the whole drill carried out.

**WHEN STANDING INSTRUCTIONS ARE TO DIVERT**

When drilling top hole and the instructions are to divert, reaction time is of paramount importance.

(Romfor barge rigs will not divert for surface hole.)

A specific drill for diverting shall be prepared for each rig and include the following:

- Simulate diverting the well as per procedure.
- Simulate lining pumps up to heavy mud and/or water.
- Essential persons must go to positions.
- Non-essential persons must go to muster points or as per emergency plan.

Simulation of diverting and pump line up should be carried out by each crew at the beginning of each tour during this drilling phase.

Muster drills should be carried out at the beginning of the top hole section, then every 7 days or crew change during this phase.

Drills shall be recorded on the Daily IADC Report and as per Emergency Response requirements.

**OTHER DRILLS**

It is recommended that several drills should be carried out prior to drilling out the casing above a high pressure or hydrocarbon zone.

A full BOP drill includes the following:

- Closure of BOP
- Circulation through choke with back pressure (500 psi)
- Mustering crew
- Calling evacuation transport
- Pressuring bulk tanks, etc.

A stripping drill includes the following:

- Standard drill while tripping
- Applying low pressure (2 - 500 psi)
• Strip through annular as per procedure (5 stands)
### HPHT Well Control Equipment Requirements – Pre-job Physical Condition Audit

<table>
<thead>
<tr>
<th>Well Control Equipment</th>
<th>Yes</th>
<th>No</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Are circulation subs fitted with seals rated for high temp?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2. Are high-temp elastomers fitted in the fixed pipe rams?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>3. Are high-temp elastomers fitted in the variable pipe rams and in the shear rams?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>4. Are high-temp elastomers fitted in fail-safe packings and seals?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>5. Are high-temp elastomers fitted in the lining of choke and kill lines? - droop hoses.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>6. Are any of the coflexip hoses “Rilsan” lined? (They should all be “Coflon” lined to be compatible with high-temp Methane gas!)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>7. Are high-temp elastomers fitted in the kill and choke line stab connector lip seals?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>8. Are high-temp elastomers fitted in the packings and seals on the 15K valves on the choke manifold?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>9. Are high-temp elastomers fitted in the bladders on the pressure transducers on the choke manifold?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>10. Are hydraulic actuators fitted on the choke manifold valves and chokes which are likely to be used under high pressure well kill situations?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>11. Are there Glycol injection points upstream of the chokes?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>12. Is there a 250 psi pressure relief valve fitted to the buffer chamber on the choke manifold lines? (This protects the liquid seal on the mud/gas separator and also the separator vessel itself, i.e., if plugged in vent line and dip tube.)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>13. Does the pressure relief valve in no. 12 vent via the overboard lines?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>14. Are the overboard lines rated to at least the pressure rating of the buffer chamber? What are the respective pressure ratings?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>15. What is the pressure setting on the device that protects the liquid seal of the dip tube?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>16. Is the device in no. 15 automatic or manually operated?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>17. Are the following readouts available:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Temperature upstream and downstream of the choke?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Pressure upstream and downstream of the choke?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Kill manifold pressure?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Choke manifold pressure?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Mud/gas separator temperature?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Mud/gas separator pressure?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>18. Where are the readouts for each of the gauges in no. 17:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Temperature upstream and downstream of the choke?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Pressure upstream and downstream of the choke?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Kill manifold pressure?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Choke manifold pressure?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Well Control Equipment</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>---------------------------------------------------------------------------------------</td>
<td>-----</td>
<td>----</td>
</tr>
<tr>
<td>• Mud/gas separator temperature?</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>• Mud/gas separator pressure?</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>19. Are both the fluid ends of the cement/kill pump rated to 15K?</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>20. Are both fluid ends fitted with liners and pistons rated to 15K?</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>21. Are additional 15K liners and pistons available as backup?</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>22. Is there a 15K kill line permanently hooked up to the cement/kill pump?</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>23. Are there at least two valves separating the cement/kill pump from the kill line?</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>24. Is there a dedicated 15K kill (coflexip) hose on the rig? Is it rigged up to the kill manifold permanently?</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>25. Are there sufficient 15K pound kelly cocks for the drilling stand (3) - single kick assembly (2), and for stabbing (1)?</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>26. When was the last time the BOP and associated well control equipment was pressure tested and accepted by the rig’s certifying authority?</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>27. What is the required frequency of the test outlined in no. 26?</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>28. When was the last time the cement/kill pump was pressure tested and certified?</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>29. Was the single kick assembly pressure tested when made up?</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>30. Has the automatic MAASP control system been disconnected?</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>31. When was the last calibration of gauges and chart recorders?</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>32. How do the different gauges compare for consistency between similar readouts?</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>33. When was the flow-show last checked/inspected?</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>34. Is the flow-show located upstream of the trip tank outlet?</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>35. When was the last calibration of the gas sensors?</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>• Rig’s total gas?</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>• Rig’s H2S?</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>• Mudlogger’s total gas?</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>• Mudlogger’s H2S?</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>36. When was the last time the Glycol injection system was function tested?</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>37. What H2S ancillary equipment will be on the rig?</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>38. Is the magnetic single shot equipment rated for high temp?</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>39. Is the following service company equipment rated for high-temperature?</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>• Drilling Jars?</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>• Accelerators Jars?</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>• RTTS?</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>• MWD?</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>• Wireline tools?</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>Well Control Equipment</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>---------------------------------------------------------------------------------------</td>
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</tr>
<tr>
<td>• HDIS?</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>• Circ subs?</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>40. Do the drillpipe tooljoints have smooth hard facing, which is flush with the bodies of the tooljoints?</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>41. Have the true-weight mud balances been accurately calibrated recently?</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>42. Is there a “master” calibrated true-weight balance on the rig for recalibrating the balances that are used at the pits and shakers?</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>43. Are there any plans to increase the height of the liquid seal to increase the blowdown capacity of the mud/gas separator?</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>44. Are there any plans to blank off the three gas line vents nearest the inlet line of the mud/gas separator to reduce the amount of liquid carried up the vent line?</td>
<td>☐</td>
<td>☐</td>
</tr>
</tbody>
</table>
## HPHT Well Control Procedure Checklist

<p>| | | | | | |</p>
<table>
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</thead>
<tbody>
<tr>
<td>1.</td>
<td>Are circulation subs drifted with tools that are to pass through them? (e.g., survey barrel).</td>
<td></td>
<td></td>
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</tr>
<tr>
<td>2.</td>
<td>Is the HDIS sub physically drifted with the circ sub-opening ball?</td>
<td></td>
<td></td>
<td></td>
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</tr>
<tr>
<td>3.</td>
<td>Is a written procedure in place to flush the kill line after every cement job?</td>
<td></td>
<td></td>
<td></td>
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</tr>
<tr>
<td>4.</td>
<td>Is a high-pressure single kick assembly rigged up for connecting the high-pressure coflexip kill hose from the kill manifold to the drillstring?</td>
<td></td>
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</tr>
<tr>
<td>5.</td>
<td>Is the minimum stock of barites on the rig? (100 MT)</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>6.</td>
<td>Is the minimum stock of cement on the rig? (80 MT)</td>
<td></td>
<td></td>
<td></td>
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</tr>
<tr>
<td>7.</td>
<td>Are there sufficient cement chemicals for setting contingency plugs? (To fill the entire openhole section).</td>
<td></td>
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<tr>
<td>8.</td>
<td>Are there suitable contingency plugback recipes on the rig?</td>
<td></td>
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<tr>
<td>9.</td>
<td>Are there sufficient stocks of LCM on the rig?</td>
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<td></td>
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<tr>
<td>10.</td>
<td>Are there sufficient stocks of glycol on the rig? (200 gallons min).</td>
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<tr>
<td>11.</td>
<td>Will kill mud be available on the rig?</td>
<td></td>
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<tr>
<td>12.</td>
<td>Have all of the tubular and sub IDs been accurately checked recently?</td>
<td></td>
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<td></td>
</tr>
<tr>
<td>13.</td>
<td>Are all tubulars and subs drifted to ensure that the HDIS dart will pass through?</td>
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<td></td>
<td></td>
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</tr>
<tr>
<td>14.</td>
<td>Will the HDIS dart pass through all of the kelly cocks?</td>
<td></td>
<td></td>
<td></td>
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</tr>
<tr>
<td>15.</td>
<td>In case of a power failure, does the emergency generator have the capacity to allow the well killing operations to continue? (i.e., start mechanism on cement/kill pump).</td>
<td></td>
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</tr>
<tr>
<td>16.</td>
<td>What is the procedure for isolating the mud/gas separator and venting wellbore fluids?</td>
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<td></td>
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</tr>
<tr>
<td>17.</td>
<td>What is the procedure for releasing/relieving pressure on the choke/kill manifold buffers and venting wellbore fluids?</td>
<td></td>
<td></td>
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</tr>
<tr>
<td>18.</td>
<td>Will there be two mud engineers on the rig for the duration of the HPHT section?</td>
<td></td>
<td></td>
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<tr>
<td>19.</td>
<td>Is there any trainee mudloggers on the rig for the HPHT section?</td>
<td></td>
<td></td>
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<tr>
<td>20.</td>
<td>Will the number of persons on the rig be kept to a minimum during the HPHT section?</td>
<td></td>
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<td></td>
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<tr>
<td>21.</td>
<td>Have onsite H2S/BHA refresher courses been run for all personnel?</td>
<td></td>
<td></td>
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<td></td>
</tr>
<tr>
<td>22.</td>
<td>Have all supervisory contractor staff down to ADs attended volumetric stripping course and HPHT course?</td>
<td></td>
<td></td>
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</tr>
<tr>
<td>23.</td>
<td>Will a pre-HPHT section meeting be held?</td>
<td></td>
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<td></td>
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</tr>
<tr>
<td>24.</td>
<td>Is a procedure in place for establishing the SCRs for the cement/kill pump via the single kick assembly and down the string?</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>25.</td>
<td>Is a procedure in place to ensure that circulation is broken every 12 hours down the kill and choke lines?</td>
<td></td>
<td></td>
<td></td>
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</tr>
<tr>
<td>26.</td>
<td>Can the top drive be disconnected at all times with the well still closed in via an IBOP, and without the string striking bottom, due to the heave effects? (i.e., can part of drilling stand be removed with well secured to ensure the string is off bottom with heave effects?).</td>
<td></td>
<td></td>
<td></td>
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</tr>
<tr>
<td>27.</td>
<td>Is HDIS to be run above the HWDP in all BHA's?</td>
<td></td>
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<tr>
<td><strong>28.</strong> Have restrictions been minimized on BHA, apart from Totco, jars, and HDIS -- i.e., MWD, nozzle size, etc. -- to ensure can pump LCM without plugging off.</td>
<td>Yes ☐ No ☐</td>
<td></td>
<td></td>
<td></td>
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</tr>
<tr>
<td><strong>29.</strong> Lag time * ROP not greater than 30 feet (90 feet when drilling with a drilling stand). Only one “bottoms up connection gas” in the well per connection. Note that any time the pumps are shut down while drilling ahead, will also be considered as “effective connection” gas in the annulus.</td>
<td>Yes ☐ No ☐</td>
<td></td>
<td></td>
<td></td>
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</tr>
<tr>
<td><strong>30.</strong> No tripping out of hole when losses greater than 10 bbls/hr.</td>
<td>Yes ☐ No ☐</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>31.</strong> What will be the accepted background gas level before work permits are withdrawn and the standby vessel notified?</td>
<td>Yes ☐ No ☐</td>
<td></td>
<td></td>
<td></td>
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</tr>
<tr>
<td><strong>32.</strong> Close in valves immediately upstream of the choke? (I.e., Always the nearest valve upstream of the choke to provide maximum contingency valves to be able to close further upstream of the choke if a valve washes out.)</td>
<td>Yes ☐ No ☐</td>
<td></td>
<td></td>
<td></td>
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</tr>
<tr>
<td><strong>33.</strong> Always equalize pressure across valves prior to opening to prevent washing of the valve!</td>
<td>Yes ☐ No ☐</td>
<td></td>
<td></td>
<td></td>
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</tr>
<tr>
<td><strong>34.</strong> Do you know the correct shut-in method?</td>
<td>Yes ☐ No ☐</td>
<td></td>
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# Well Control Worksheet

## General Information

<table>
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- ☐ Foreign
- ☐ Domestic
- ☐ Onshore
- ☐ Offshore
- Weather Condition:

## Operator Information

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## Contractor Information

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<tr>
<th>Rig Name/Number:</th>
<th>Rig Type:</th>
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## Well Information

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<th>Lease Name:</th>
<th>Field Name:</th>
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<th>Well Location:</th>
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<tr>
<th>Water Depth:</th>
<th>Tide/Seas:</th>
<th>Wind Direction/Speed</th>
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<th>True Vert. Depth:</th>
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<th>Relief Well Location Availability:</th>
<th>Closest Offset Well:</th>
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<th>Closest Town/City:</th>
<th>Miles From:</th>
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| Directions to Location: | |
|-------------------------||

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<th>Closest Airport:</th>
<th>Runway Length:</th>
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## Blowout Information

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<tr>
<td>Fire:</td>
<td>H₂S:</td>
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<td>------------</td>
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<tr>
<td>CO₂:</td>
<td>Geothermal:</td>
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<td>Other:</td>
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<tr>
<td>Gas:</td>
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<tr>
<td>Condensate:</td>
<td>Salt Water:</td>
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# Well Information Form

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<tr>
<th>DP - CSG Anulus</th>
<th>Drill Pipe #1:</th>
<th>HWT-OP #2:</th>
<th>Drill Collars #1:</th>
<th>Measured Depth:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cap Bin/FT.</td>
<td>OB</td>
<td>OB</td>
<td>OB</td>
<td>FT.</td>
</tr>
<tr>
<td>Bila</td>
<td>Line/FT.</td>
<td>Line/FT.</td>
<td>Line/FT.</td>
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<table>
<thead>
<tr>
<th>DP - CSG Anulus</th>
<th>Drill Collars #2:</th>
<th>Casing:</th>
<th>Liner:</th>
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<tbody>
<tr>
<td>Cap Bin/FT.</td>
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<tr>
<td>Bila</td>
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<table>
<thead>
<tr>
<th>DP - LINER Anulus</th>
<th>Drill Collars #2:</th>
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<th>Liner:</th>
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<tr>
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<td>OB</td>
<td>OB</td>
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<tr>
<td>Bila</td>
<td>Line/FT.</td>
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<th>DP - Hole Anulus</th>
<th>Pump # 1 Triplex</th>
<th>Surface Volume</th>
<th>Pump # 2 Triplex</th>
<th>Volume</th>
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<tr>
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<td>OB</td>
<td>OB</td>
<td>FT.</td>
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<tr>
<td>Bila</td>
<td>% Efficiency</td>
<td>% Efficiency.</td>
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<th>DC - Hole Anulus</th>
<th>Slow Pump Info. #1</th>
<th>Slow Pump Info. #2</th>
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<tr>
<td>Cap Bin/FT.</td>
<td>Bbls / Min.</td>
<td>Bbls / Min.</td>
</tr>
<tr>
<td>Bila</td>
<td>Stk / Min.</td>
<td>Stk / Min.</td>
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</tbody>
</table>

**Lost Circulation Will Occur With:**

**Maximum Equivalent Mud Weight:**

**PPG. Maximum Gradient:**

**Barrels** | **Strokes** | **Minutes**
--- | --- | ---

**Annular:**

**Inside Drill String Totals:**

**ANULUS TOTALS:**

**WELL SECTIONS**

**STROKES AND MINUTES**

**Surface to Bit**

**Bit to Shoal**

**Bit to Surface**

**Surface to Surface**
<table>
<thead>
<tr>
<th>Time</th>
<th>Description</th>
<th>Contact</th>
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APPENDIX A: GAS BEHAVIOR IN OIL-BASED MUD

Gas behavior in oil-based muds can cause well unloading with no warning to the Driller. The bubble point is the pressure at which gas breaks out of solution and behaves according to gas law.

KEY PRACTICES TO PREVENT WELL UNLOADING

WHILE TRIPPING

- Limit tripping speeds to minimize swab surge pressures.
- Monitor hole fill in and out of the hole.

WHILE DRILLING

- Adjust detection equipment alarms as low as possible.
- Circulate bottoms up at any increase in gas levels.
- Check mud weights in/out frequently.
- Flow check all drilling breaks.

BE ALERT TO ACTIVITIES THAT ALLOW UNDETECTABLE INFUX VOLUMES!

Watch for the following:

- Swabbing when picking up off bottom
- Drilling through gas sands
- Stacking gas cleanout with sub-sea stacks

CIRCULATE BOTTOMS UP THROUGH OPEN CHOKE WITH WELL SHUT IN!

Be especially watchful during the following:

- The last 2000 – 3000 feet
- When drilling in deepwater with sub-sea stack

KICK DETECTION AND WARNING SIGNS

SITUATIONS THAT CAN MASK A SMALL INFUX

Be aware of the following:

- Partial loss of circulation
- Mud weight adjustments while drilling
- Solids control equipment and degassing mud
• Newly drilled hole volume
• Spills and leaks from surface equipment
• Loss of kelly volume during connections
• Note: A kick of 5 bbls or less can occur completely undetected under normal operating conditions.
APPENDIX B: TERTIARY WELL CONTROL

If secondary control cannot be maintained because of a downhole problem or equipment failure, certain emergency procedures can be implemented to prevent total loss of control.

There are not many established tertiary well control procedures, because each situation tends to require an individual solution.

Several procedures which have been widely used, however, include the following:

- Barite plug
- Gunk plug
- Cement plug

**BARITE PLUG**

A barite plug is a mixture of barite and water or diesel designed to bridge the hole. The plug is spotted in place, bridging the hole as barite settles.

The effectiveness depends on the high density of barite and its ability to form an impermeable barrier. The plug is displaced through the string and, if possible, the string pulled back above the plug.

A successful slurry has the following properties:

- High-quality barite with low clay content
- Low viscosity and yield point to allow rapid setting
- High density (3 ppg greater than the mud density)
- High fluid loss to allow rapid dehydration which may also help the hole to pack off
- Two types of barite plug can be used:
  - Barite – water
  - Barite – diesel

**BARITE – WATER**

Use this plug with water-based mud and follow this procedure:

- Choose desired weight.
- Calculate volume required to produce plug of sufficient length (300 – 450 feet).
Ingredients per bbl of slurry:

<table>
<thead>
<tr>
<th>Mud Weight</th>
<th>18 ppg</th>
<th>20 ppg</th>
<th>22 ppg</th>
</tr>
</thead>
<tbody>
<tr>
<td>Water (bbl)</td>
<td>0.643</td>
<td>0.569</td>
<td>0.495</td>
</tr>
<tr>
<td>Barite (bbl)</td>
<td>536</td>
<td>647</td>
<td>756</td>
</tr>
</tbody>
</table>

- Mix barite in a mixing hopper directly into drillpipe using water containing:
  - 0.7 ppb Sodium acid pyrophosphate (SAPP)
  - 0.25 ppb caustic
- Displace with mud into annulus, leaving the mud in the drillpipe about 2 bbls above that in the annulus.
- Pull out of plug.
- Circulate on top of plug for several hours if possible.

Note: An alternative to SAPP as a thinner is to use lignosulphonate at 0.4 ppb. Lignosulphonate is much affected by contamination and thermally stable, but reduces the fluid loss by a factor of 10.

Barite – Diesel

Use this plug with oil-based mud and follow this procedure:

- For an oil-based mud, a slurry of barite and diesel is preferred. Ingredients per barrel:

<table>
<thead>
<tr>
<th>Mud Weight</th>
<th>18 ppg</th>
<th>20 ppg</th>
<th>22 ppg</th>
</tr>
</thead>
<tbody>
<tr>
<td>Diesel (bbl)</td>
<td>0.610</td>
<td>0.54</td>
<td>0.47</td>
</tr>
<tr>
<td>Barite (bbl)</td>
<td>570</td>
<td>680</td>
<td>780</td>
</tr>
</tbody>
</table>

- Add an oil-wetting agent to increase settling (0.5 ppb).
- The pumping procedure is the same as for water.

Gunk Plug

Gunk is a mixture of bentonite and diesel. It is a possible alternative to a barite plug in the case of a water flow. It does not work well with gas and should be considered short term (i.e., set a cement plug on top).
The oil acts as a carrier for the bentonite, not allowing hydration and swelling. As water comes into contact with the bentonite, it hydrates and sets as a clay cement.

**CEMENT PLUG**

A cement plug can be used to seal off flow in the bottom of the wellbore. It usually offers little chance of retrieving the string and involves abandonment of the well and loss of most of the down hole tools. It is also likely that the drill string will become plugged, thus a second attempt will not be possible should the first fail. In well control terms, it should be considered the final option.

Cement plugs are set by pumping a quantity of accelerator (quick setting) cement into the annulus via the string. Pumping cement continues until pressure shows a bridge has formed.

In high angle holes or when setting off bottom, a highly viscous slug should be spotted below to prevent cement dropping through the mud.
APPENDIX C: BOP DRILLS

DRILLS

WHILE DRILLING

Observe the following while drilling:

- A drill may be conducted in open or cased hole. However, if the drill string is in the open hole, the well should not be shut in.
- The PIC should initiate the drill by manually raising a pit level float.
- The Driller is expected to detect the pit gain and take the following steps to secure the well:
  - Pick up the kelly (or topdrive) until the tool joint clears the BOPs and the kelly cock is just above the rotary table.
  - Shut down the pumps.
  - Check for well flow.
  - Report to the Operator’s Representative.
  - Record the time required for the crew to react and document the drill on the IADC Report.

WHILE TRIPPING

A drill while tripping familiarizes the drill crew with the shut-in procedure to use for a kick during a trip.

Without notice, the PIC should initiate the drill by raising the trip tank float to indicate a pit gain.

The Driller is expected to take the following steps to secure the well:

- Stop other operations.
- Sound the kick alert alarm.
- Install the string safety valve.
- Close the annular preventer.
- Record casing and drill/ workstring pressure.
- Notify Drilling Supervisor that well is shut in.
- Record the drill on the IADC Report.

PIT DRILLS AND FUNCTIONAL TESTING OF BOP EQUIPMENT
To familiarize members of the drill crews with the procedure and to minimize the reaction time, a series of drills shall be held at least once per tour, if hole conditions permit, and until the Rig Manager/Toolpusher is satisfied that every member of the crew is familiar with the entire operation.

All rig floor crews returning from a field break should perform these drills as soon as possible after returning to rig duty.

Once satisfactory performance has been achieved, the drills shall be held at least once per week for each crew. Any fall in standards should be immediately rectified by an increase in the frequency of drills.

On the operational tests and drill procedures report form, the prefix “D” denotes a drill. The prefix “O” denotes an operational test.

“DI” indicates on all reports that a pit drill while tripping has been performed. “R” indicates that the remote controls were used. On morning reports, just “DI” or “DIR” are necessary. The IADC Report records all times and any other relevant information.

Log the following time in the IADC report: Overall time, from the raising of the pit level indicator to when the last person is in position, with all steps set out in the program completed and the well secured.

**Note:** The drilling crew must be organized into a team with each member assigned specific duties. Establish standard signals to communicate.

All functional tests must occur while out of hole or as soon thereafter as possible. All tests are conducted under the direction of the PIC. Advise the Operator’s Representative of the intention to perform all tests, so that he or she can witness the procedures. Record the test results and the time to close each preventer in the IADC Report and have it initialed by both the Operator’s Representative and the PIC.

**Tests**

Operational BOP tests shall be conducted from the Driller’s control system on the floor and the remote control unit on alternative days. (Report using “R” when carried out from remote control units.) The tests to conduct are:

- **BOP Rams (Blind) 01 (R)**
  Perform test when the drill string is out of hole. Close blind/shear rams. Check correct fluid volume on control meter. Record time to close and fluid volume.

- **BOP Rams (Pipe) 02 (R)**
Ensure the pipe ram is positioned midway between tool joints on drillpipe connections before beginning test. Close pipe rams. Check correct fluid volume on control meter. Record time to close and volumes.

- **Spherical Preventer 03 (R)**
  
  Ensure spherical preventer is positioned midway between tool joints on drillpipe or drill collar connections. Close spherical on drill collar or drillpipe. Open, and record the time closed.

  **Note:** All tests involving closure of ram or bag preventers should be carried out as quickly as possible to ensure minimum closed time.

  Where possible, routine tests should, with the exception of spherical preventer, be carried out while out of hole to coincide with trip for bit change.

- **Kelly Valves 04**
  
  Open and close upper and lower kelly cocks, noting that each valve opens and closes freely.

- **Drill String BOPs 05**
  
  Open and close ball-type and spring-type safety valves (inside BOPs). Check crossover subs for drill string safety valve subs.

- **Pit Level Indicator 06**
  
  Raise and lower pit level floats to check alarm settings and alarm signal. (Record on chart.)

- **Degasser 07**
  
  Line up the degasser with the degasser centrifugal pump and check for correct operation. Conduct operational tests on the degasser weekly. (Record when test was conducted on the IADC Report Form.)

  - Warn Driller beforehand of intention to conduct any drill or test.
  
  - To monitor ram or annular preventer wear against usage, keep an updated log indicating the number of times each ram or annular preventer has been operated.
PIT DRILLS

Drills shall be conducted under the direction of the PIC. The Operator’s Representative must be advised of the intention to test so that he or she can witness the procedure. The results are to be recorded on the IADC Report Form and initialed by the PIC and Operator’s Representative.

Procedures are given for four different pit drills:

- **D1 Trip** While tripping in or out of hole
- **D2 Drilling** While on bottom circulating or drilling ahead
- **D3 Out of hole** When out of hole, logging, or changing bit
- **D4 Diverting gas in riser** Deepwater

Each of these conditions imposes special problems, though all are closely related to maintaining control and preventing blowout.

All tests involving closure of rams or spherical preventers should be carried out as quickly as possible to ensure minimum closed time.

Before closing ram or spherical preventers on the drill string, make sure that the ram or spherical preventer is positioned midway between tool joints on drillpipe/drill collar connection.

**Note:** Ram or spherical preventers should never be closed on stabilizers or spiral drilled collars.

Do not use back pressure valve (BPV) with drop-in dart during drills.

KICK WHILE TRIPPING

Follow these instructions:

- Raise float in trip tank to simulate influx.
- Driller notices changes in mud pit level, beyond that of the pipe being run in or pulled out, by audio and visual signals. (Buzzer and pit level indicator.)
- Driller notifies crew.
- Driller spaces out pipe just above rotary table.
- Shut off pumps if circulating with TDS.
- Install FOSV (TIW), close FOSV if no TDS connected.
- Close annular preventer.
• Open upper choke line failsafes on BOP. Line manifold up against closed choke and upstream valve.
• Record SICP and influx volume.
• Record on IADC Report.

Additionally, perform the following procedures when required:
• Space out string. (Driller must have record of ram depth/tool joint spacing and be aware of tidal variations.)
• Install circulating head.
• Land on (upper) pipe rams using drill string compensator.
• Open spherical preventer.
• Record total time.

**KICK WHILE DRILLING**

Follow these instructions:
• Raise float in mud pit to simulate influx.
• Driller notices change in level.
• Driller alerts crew.
• Shut down rotary.
• Pick up off bottom, space out pipe.
• Shut down pumps.
• Close BOP (normally annular).
• Open upper choke line failsafes against closed choke and upstream valve.
• Record SIDPP and SICP and influx volume.
• Inform PIC.
• Record on IADC Report.
Additionally, perform the following procedures when required:

- Close lower kelly cock.
- Set pipe in slips. Set back kelly, install circulating head.
- Close (lower) rams and lock.
- Open spherical preventer.
- Land string on rams.
- Record total time.

**Kick While Out of Hole Drill**

Follow these instructions:

- Raise float in trip tank to simulate influx.
- Driller recognizes gain and alerts crew.
- Close blind shear rams.
- Open upper choke line valves against closed choke and upstream valve.

**Diverting of Gas in Riser Drill - Offshore**

- This drill to be performed when drilling in deepwater, immediately after the well has been secured. Follow these instructions:
  - As soon as the well is secure, monitor the riser on the trip tank.
  - Simulate flow from riser.
  - Driller observes flow, alerts crew.
  - Close diverter with simulated returns to the diverter line.
APPENDIX D: DRILLING OF HIGH PRESSURE/HIGH TEMPERATURE (HPHT) WELLS

INTRODUCTION

Drilling operations involving high pressure/high temperature (HPHT) present unique problems involving personnel and equipment and require Romfor supervisors to take special precautions.

Romfor rigs in a worldwide drilling operation may encounter combinations of HPHT well conditions in one of two ways:

- In a planned and programmed penetration of HPHT formation provided by the Operator's well prognosis.
- As a "surprise" in a wildcat situation.

In either case, managing the drilling operations and controlling these known hazards is paramount.

Before performing any operations in an area where the potential of HPHT exists, a Pre-Job Physical Condition Audit shall be conducted. In addition, a procedural review shall be conducted utilizing the HPHT Well Control Procedure Checklist

DRILLING PROCEDURES

TRIPPING

Typical objectives of HPHT tripping procedures are:

- To avoid swabbed kicks and any other kicks while tripping.
- To confirm the pressure at total depth (TD) of hole section when drilling in transition zones.
- To confirm that the mud weight is sufficient to hold back the formation while tripping.

Pumping out of the hole (with pump rates significantly higher than the pulling rate) ensures that the well will not be swabbed. Take precautions to pump far enough out so that swabbing does not take place. This may be well above the shoe.

A swab test using the bottommost stand will test formation pressures at TD. A short trip through a new hole section (with the pumps on) will confirm the overbalance (or lack of) for a newly penetrated HPHT reservoir section.
In all cases, it is essential that tripping practices are consistent and records are kept so that a comparison can be made with the previous trip. It is the responsibility of the Driller and Toolpusher to ensure that this is done in situations where HPHT conditions exist or are suspected.

**HPHT Procedures Prior to Tripping**

Meet the following requirements before tripping in known or suspected HPHT conditions:

- The pipe must not be tripped out of the hole unless it is safe to do so. In particular, the drill pipe must not be tripped out if the weather forecast precludes getting back on bottom.
- The Driller and Mudlogger should complete separate trip sheets.
- A trip sheet from the previous trip out of the hole must be available at all times. Intervals where overpulls occur should be recorded on the trip sheet.
- The Operator should provide the Driller with the necessary information about the trip (i.e. reason for the trip), prevailing pore pressure regime, and tripping overbalance.
- The Driller shall ensure that the rig floor is fully prepared to shut in the well and that FOSVs, nonreturn valves, and darts suitable for the dart sub are ready for use.
- Drillers shall check that the dart passes through the FOSVs.

**General Notes on Tripping**

Consider the following during all trips where HPHT conditions are known or suspected:

- When pumping out of the hole to the casing shoe or top of the liner, circulate at rate of 75% to 100% of that while drilling.
- Make sure pump rate is greater then the displacement of the pipe removed from the borehole.
- Continue to pump through any liner because there may still be swabbing tendency due to small annular clearance.
- When breaking off a stand, switch off the pumps and stop flow before stopping the rotation. This reduces the chances of sticking the pipe. The string should be stationary for as short a time as possible.
• Record the displacement volumes on the trip sheet. It is crucial that the point at which displacement is recorded is the same each stand to enable a meaningful trend to be observed. Once at the shoe (and at a point where it has been agreed that the pipe can be pulled dry), check that the pit volume is the same as the volume when the bit was on bottom less the hole fill for the pipe displacement. Perform a 15-minute flow check on the trip tank with the trip tank pump running.

• Continue to rotate the pipe while performing the flow check. If there is a motor on the bottom hole assembly (BHA), pumping out of the hole must stop when the bit reaches the shoe.

• While tripping in HPHT wells, a careful and accurate record of displacement must be maintained independently by the Driller and Mudloggers. Regular communication between the Driller and the Mudloggers should occur; any variation should be discussed and resolved before continuing. Any discrepancies should be flow-checked immediately and if necessary the well shut in. Because of high temperatures, high gels, and high weights, the volumes in the initial stages may not be as calculated. These should be fully investigated as the well progresses. A trend of displacement should become apparent. It is important that the previous trip sheets be kept as a reference to aid the next trip.

• When pumping a heavy slug, make sure that the slug weight and the amount of dry pipe is kept consistent throughout the section. A historical trend can be established which can be referred to on each subsequent trip. Allow time for the slug to stabilize with the drill pipe open and confirm that the volume of returns is correct. Rotate the pipe while the slug is settling to break the gels. Install a kelly cock on the string if the trip is interrupted for any reason, such as a mechanical failure or flow check. Leave the valve open to monitor the well.

• When out of the hole, circulate across the hole and to the trip tank with the trip tank pump. Keep the shear rams open. The Driller must be on the drill floor at all times unless relieved by the Toolpusher.

• The Mudloggers must continuously monitor the trip tank and notify the Driller of any discrepancies.

• The Driller has full authority to flow check or to shut in the well as he or she sees fit and is expected to fully investigate any occurrences which deviate from a stable trend.

**Tripping Out in a HPHT Transition Zone**
Beyond wanting to avoid an induced kick, one of the objectives of tripping in the transition zone is to confirm the pressure (or lack of pressure) at the TD of the hole penetrated. This tripping procedure involves the following:

- When the decision is made to trip out, circulate the equivalent of the volume of the top of the annulus.

- Shut the pump off with the top drive still on.
- Stroke the pipe ½ stand (45 feet) at a speed greater than normal trip speed.
- Run back to bottom and flow check.
- Pump for 30 seconds.
- Stroke the pipe ½ stand (45 feet) at a speed greater than normal trip speed.
- Run back to bottom and flow check.
- Pump bottoms up. When the decision is made to trip out, circulate the equivalent of the volume of the top of the annulus.
- Assess the gas levels of the mud exiting the mud gas separator and flowing into the mud trough (though this can be difficult, unless the gas measurement equipment is mounted downstream of the choke). If the gas level is acceptable, pump out of the hole to shoe at a minimum and then slug the pipe and pull stand dry. If the gas levels are high, raise the mud weight, adjust mud properties, and repeat the swab test before pumping out of the hole.

Note: These procedures constitute a HPHT “swab test.”

TRIPPING OUT OF A HPHT WELL

There are two basic approaches for tripping out of the HPHT hole. These are:

- Pump out to ensure that no hydrocarbons are swabbed in.
- Keep accurate trip tank records to accurately monitor any gains.

Given the capabilities of Romfor rigs, it is recommended that pumping out is the safest approach to HPHT well sections. At the same time, a deliberate “swab test” can determine how close to balance the wellbore hydrostatic pressure actually is. This is very much in line with the overall approach, which is:

- Establish pressures whenever possible and before proceeding with drilling, tripping, or coring.
The objective of this procedure is to avoid an induced kick. The tripping out procedure is as follows:

- When the decision is made to trip out, circulate the equivalent of the volume of the top of the annulus.
- Make a short trip at normal speeds and with the pump on, through all the new formation penetrated.

- Run back to bottom and flow check.
- Pump bottoms up. When bottoms up reaches suspect HPHT zone, direct returns through the choke and mud gas separator.
- Assess the gas levels of the mud exiting the mud gas separator and flowing into the mud trough. If the gas level is acceptable, pump out of the hole to shoe at a minimum and then slug the pipe and pull stand dry.
- If the gas levels are high, raise the mud weight, adjust mud properties, and make a short trip with pump on to confirm overbalance.

Notes:

- In this hole section it is likely that pumping out of the hole will prove to be the safest and most effective way of tripping. The check trip is included in any case to assess downhole pressures.
- Note also that pumping out should be continued until it is safe to pump a slug and pull a dry string. With the mud properties and proximity of the casing shoe to the producing formation, this implies that pumping out might be continued until some distance inside the casing shoe.
- If a mud motor is in use, pumping out should be stopped once the bit is at the shoe.
TRIPPING IN A HPHT HOLE

Take great care to minimize surge pressures when tripping in the well. Trip speeds may need to be reduced if margins are low.

- When making up the BHA, ensure that the float valve has been checked.
- When tripping back into the hole, monitor the well on the trip tank with the trip tank pump running.
- Limit tripping speed in the hole to the speed determined from the surge pressure calculations.
- Check the correct volume of mud is being displaced from the well. Flow check the well if any discrepancies occur. Shut in immediately if any flow is observed.
- Break circulation at an appropriate depth (or depths) and circulate string contents at a reduced rate to avoid pressuring up the exposed formations (Note: you will be circulating cooler mud, which has a significantly higher viscosity). If there is a turbine, motor, or core barrel in the hole, then the off bottom circulation rate may have to be restricted.
- Break circulation at the casing shoe and displace the hole to the drilling mud applicable.
- Perform a flow check and run in to bottom. Consider washing down from the shoe to protect the formation by reducing the gel effect and hence prevent creating losses. As a minimum, wash at least the last stand to bottom. If any reaming is required, recognize that this is probably the most crucial time of the trip and that it is very easy to create losses as the filter cake is disturbed by the drill string rotation.
- Always circulate bottoms up when returning to bottom until reservoir pressures are known. The annular preventer should be closed with the pipe slowly rotated.

Note: Because barite sag can be a problem in HPHT wells, it is advisable to circulate bottoms up and get the mud in balance before drilling ahead on wells that suffer from adverse barite sag. It is necessary to circulate the mud into balance at random stages while tripping into the well.

BALLOONING OR FLOWBACK IN HPHT WELLS

Ballooning or flowback occurs when mud which was either lost to fractures in the formation or into the ballooning of the wellbore is given back when some of the excess pressure in the
wellbore is relieved. When the excess pressure is relieved, the fractures squeeze back some of the mud that entered or the balloon returns to its original size. It is recommended that the driller’s method be used for well control purposes. This method allows the influx to be circulated to surface and the influx examined before the mud is weighted up. If the ballooning diminishes flow (and therefore had no associated hydrocarbon), operations could be resumed with the same mud weight. Raising the mud weight, which would happen automatically with the wait and weight method, might just make the situation (severity of ballooning) worse.

**PROCEDURE FOR MINIMIZING BALLOONING IN HPHT WELLS**

The sequence of activities to reduce ballooning is as follows:

- Start pumps to impose annular friction pressure on wellbore in addition to mud hydrostatic (Note: the annular friction pressure is significant and may amount to 300 psi or more drilling circulation rate.)
- Flow mud to formation.
- Turn pump off and take away annular friction pressure.
- Get back some or all of the mud previously lost to the formation.

It is imperative to keep accurate logs of the amount of mud lost to the formation and subsequently gained back. It is recommended that both the Driller and Mudlogger keep logs. Accurate records are the key to successfully managing ballooning. The difficulty with ballooning in HPHT wells is telling that it is the extra mud coming back and not a genuine kick. Unless you are sure that it is the lost mud being returned, the gain when the pump is turned off must be treated as an influx.

It is important to avoid ballooning in the first place by keeping the wellbore pressure less than the fracture propagation pressure. Some safety considerations for flowback follow.

**PROCEDURES FOR HANDLING MUD FLOWBACK IN HPHT WELLS**

Flowback is the volume of mud (in barrels) that flows out the top of the well when the pump is turned off. To reduce the risk associated with rogue flowback, the following procedure may be used:

- The first time flowback is encountered, consider it a real kick.
- The driller’s method is suggested so that the influx can be looked at before the mud weight is raised.
• Once the ballooning is suspected, the amount of influx allowed back into the wellbore should be agreed upon by the PIC and the Operator.

• The rate of influx into the wellbore should be closely monitored. Ballooning should result in a steady or declining rate of influx. If the rate of influx is increasing at all, the well should be shut-in immediately and the influx circulated out as a kick.

Fluid should not be bled from the well without first consulting the Toolpusher. If consistent flowback is occurring, more specific rules can be set up as to what volumes of fluid can be bled off without specific authorization from the Rig/Operations Manager. It is essential that all operations be carried out consistently. The PIC is responsible for ensuring that sufficient information is relayed to the Driller.