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Preparation, Review, Approval

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Reviewed By	**Name**	**Title**	**Date**
Approved By	**Name**	**TITLE**	**Date**

Registration and Distribution

DOCUMENT NAME	DOCUMENT HOLDER	COPY NO.
Well Control Manual	HSE Manager	1
Well Control Manual	Operations Manager SD3, SD4, SD7	2
Well Control Manual	Rig Manager SD 3	3
Well Control Manual	Rig Supt SD 3	4
Well Control Manual	Ops Manager SD 5 and SD 2	5
Well Control Manual	Rig Manager SD 5	6
Well Control Manual	Rig Supt SD 5	7
Well Control Manual	Operations Manager SD 6 and SD 1	8
Well Control Manual	Rig Manager SD 6	9
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Revision History

DATE	PAGES	REVISION	REASON FOR UPDATE
26/06/06	All	Rev June 06	Change of logo
16 Jan 07	All	Rev June 06	Change of logo and updates
September 07	All	Rev June 06	Amendments

Suggestions for Improvement

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** PLEASE NOTE THAT ON A JACK UP RIG THE DUTIES OF OIM AND RIG SUPERINTENDENT WILL BE THE SAME.

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INTRODUCTION

PURPOSE

The purpose of this manual is to provide a clear, easy to use reference document of SeaDrill (referred to as the Company) well control policy and both Company, and Rig specific well control procedures. It is intended to provide personnel managing Company mobile offshore drilling units (MODU's), and drilling operations onboard Company installations, with an easy to use aid to well control and well control decision making.

This manual is not intended to replace well control teaching manuals, nor is it intended to absolve personnel with a well control function from the necessity of acting safely, exercising sound professional judgment, and following, at all times, "good oilfield practice".

The Company's drilling and other well related operations are designed, planned and conducted with the intention of maintaining primary, or hydrostatic, well control. While an installation is engaged in well operations, the drill floor will be manned at all times by a Company employees with a minimum well control qualification required by the relevant authorized bodies in the area of operation. IWCF will be the standard used.

Where primary well control has, for whatever reason, been lost, it is the responsibility and duty of the Driller to act as quickly as is safely possible to instigate secondary well control, normally by shutting an element of the blowout preventer. The Company's preferred method is the "fast shut in method", unless modified, for a specific period, by bridging documents.

Where well kill procedures involving circulation are necessary, one of the forms of constant bottom hole pressure method will be used. If for some reason constant bottom hole pressure methods of killing a well are not immediately possible, operations should be directed towards arriving at a position where constant bottom hole pressure methods are achievable.

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1.0 PREPARATION

1.1 RESPONSIBILITIES

1.1.1 Offshore Installation Manager (OIM)

The OIM has, at all times, the ultimate responsibility for all operations carried out onboard the installation. To prepare the installation and its crew for well control operations he must ensure that those he appoints to positions with responsibility for well control are trained and competent to fulfil those responsibilities, and familiar with the installation's well control equipment.

The OIM is responsible for ensuring that the installation's well control equipment is supplied "fit for purpose" and maintained in this condition.

The OIM is responsible for maintaining and implementing the installation's Well Control Plan as defined in the Company's Well Control Procedures and the Company Emergency Response Manual. He will call on the assistance of all other members of the vessel's crew to assist in the development and implementation of the plan.

1.1.2 Rig Superintendent/Toolpusher

The Rig Superintendent/Toolpusher, as the person in charge of drilling operations, is responsible to the OIM for the maintenance of well control on wells drilled, completed, worked over, suspended or abandoned by the installation.

The Rig Superintendent/Toolpusher will be called on to assist the OIM in the development and implementation of the installation's Well Control Plan.

To prepare for well control operations, the Rig Superintendent/Toolpusher is responsible for instructing and exercising the crew in their well control duties and ensuring that all well control equipment, including blow-out preventers, mud circulating, mud monitoring and mud conditioning equipment, are maintained in a "fit for purpose" condition.

1.1.3 Captain/Bargemaster

The Captain / Bargemaster, as person in charge of marine operations on the installation, has the responsibility of cooperating in the development of the installation's well control planning in general and "move off" planning in particular.

In any well control situation, the Bargemaster will have particular responsibility for logistics, forward planning and weather forecasting. It will be his responsibility to monitor, present and forecast weather conditions and advise the OIM and Rig Superintendent/Toolpusher on predicted vessel motion and evacuation capabilities.

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It will be the Bargemaster's responsibility to assist the OIM in the formulation of "precautionary evacuation" plans and, if necessary, the implementation of those plans.

1.1.4 Driller and Drill Crew

The Driller is to be in direct control of drilling operations, must ensure that he and his crew exercise their well control duties, as directed by the Rig Superintendent/ Toolpusher, so as to become, and remain, familiar with the actions to be taken on detection of a well control problem.

The Driller will be required by the OIM to assist the Rig Superintendent/Toolpusher in the development and implementation of the installation's Well Control Plan.

The Driller is responsible for maintaining and updating "pre kick data" and taking and reporting "slow circulating rates", at specified intervals.

It is the Driller's responsibility to check that safety valves and all equipment required for monitoring and recording drilling fluid volumes, flow rates, pump speed and casing, and drill pipe pressures is in a serviceable condition and ready for immediate use. He has a duty to immediately report any deficiencies found to the Rig Superintendent/ Toolpusher.

1.1.5 Operator's Representative

The Operator's Representative has a responsibility to the OIM to provide specialist advice on well control. He has a duty to make available to the OIM and the Rig Superintendent/Toolpusher any information about the operating area, such as, offset well data, seismic data or any other relevant information in his, or his Company's, possession. This is of vital importance, particularly in the planning stages, for the safety of the operation, personnel, installation and the environment.

The Operator's Representative has a duty to participate fully in the development of the installation's Well Control Plan for the specific location. The Operators Representative will also have a responsibility to oversee and assist in well control drills, as per section 1.3.

1.1.6 Third Party Employees

Certain "Third Party" employees may also have well control functions. Although typically employed under contract to the Operator, and reporting directly to the Operator's Representative, they will be appointed by the OIM to assist in the development, and possible implementation of the installation's Well Control Plan.

The following positions, and any others required by the OIM, are normally involved in formulation of the well control plan and if necessary the plan's execution:-

- Mud engineers
- Mud Loggers

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- Cementers

1.2 PLANNING

1.2.1 The Well Control Plan

The OIM, with the assistance of the Rig Superintendent/Toolpusher, the Operator's Representative and whomever else he calls upon, will develop a "Well Control Plan". This plan will seek to cover, in as much detail as required, all well control eventualities, which can be foreseen for the particular well.

The purpose of the plan will be to clarify, for all those involved in well control operations, the duties and actions required of them.

The Well Control Plan must, as a minimum, cover the following topics:-

1.2.1.1 Crew Positions and Duties during Well Control Operations

Specific actions to be taken in the event of a loss of primary well control. The Company's drill crews will be well practiced in their **normal** functions during a loss of primary well control. The plan should stress any variations from the "normal", and ensure that second and third party personnel are aware of the duties required of them.

1.2.1.2 Well Control Decision Making

Advice and assistance, in the form of flow charts, to simplify well control decision making.

1.2.1.3 Well Control Logistics

To clarify the detail of how things are going to be accomplished and how problems are going to be overcome. Possible headings in this section might be "communications", "barite supplies", etc.

1.2.1.4 Pre-kill Meetings

To specify who will attend planning meetings once a well control problem has been identified.

1.2.1.5 H_2S Contingency

Contingency plans for actions to be taken on detection of H_2S gas. (Refer to the Company's Emergency Response Manual).

1.2.1.6 Pollution Control/Damage Limitation/Loss Management

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To set out available pollution control options. These should include operator supplied pollution control equipment and how to call out pollution control support.

1.3 WELL CONTROL DRILLS

1.3.1 Purpose of Well Control Drills

The purpose of BOP (Well Control) Drills is to familiarise the participants with techniques that may be implemented in the event of a kick.

One of the major factors which influence the wellbore pressures after a kick is taken is the volume of the influx. The smaller the influx, the less severe will be the pressures during the well kill operation. In this respect, it is important that the drill crew react quickly to any sign that an influx may have occurred, and promptly execute the prescribed control procedure. Drills should be designed to reduce the time that the crews take to implement these procedures.

The relevant Drills should be carried out as often as is necessary, and as often as well conditions permit, until the Drilling Supervisors, (both Company and Operator), and the OIM are satisfied that every member of the drill crew is familiar with the entire operation.

Every effort must be made to ensure that drills are carried out in the most realistic manner possible. Where practical, there should be no difference between drills and actual control procedures.

Once satisfactory standards have been achieved, the drills should be held at least once per week. If standards fall unacceptably, the Drilling Supervisors or OIM should stipulate that the Drills are conducted more frequently.

1.3.2 Kick While Tripping

The purpose of this drill is to familiarise the Driller and crew with the shut-in procedure that will be implemented in the event of a kick during a trip. This drill should only be conducted when the bit is inside the shoe of the last casing string.

1. Set slips.

2. Install the (open) drill pipe safety valve and close.

3. Close annular preventer (at reduced annular pressure).
   - 3a. Ensure choke/kill manifold is closed.
   - 3b. Open BOP upper outer, and inner choke valve.

4. Check well is shut in. Check pre-calculated BOP space out - increase annular pressure and full operating pressure.

5. Pick up a stand of drill pipe and make up top drive. (Activate DSC).

6. Notify Rig Superintendent/Toolpusher & Operator's Representative that the well is shut-in.

7. Line up standpipe manifold.

8. Open safety valve and record pressures.

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9. Stop other operations.

With reference to Paragraph 1.3.1 (ii) the vital sections of this drill are steps 1-3. It will not be necessary to complete each step (1-9) of the drill each time it is performed, but it is recommended that steps 1-3 are practiced once a trip.

It is expected that steps 1-3 will take about 60 seconds.

Performance of the complete drill (steps 1-9) should take less than 15 min.

1.3.3 Kick While Drilling (On Bottom)

The purpose of this drill is to familiarise the crew with the control procedure that will be implemented in the event of a kick while drilling. This drill may be conducted either in open or cased hole. However, if the drill is conducted with the drill string in open hole, the well will not be shut-in.

Without prior notice, the Rig Superintendent/Toolpusher gradually increases the apparent pit level by manually raising the float or transferring mud to give an apparent fluid gain.

The Driller is expected to detect the pit gain and take the following steps:-

1. Pick up the drill string until the tool joints clear the BOP. (Space out in accordance with the pre-recorded space out data).

2. Shut down the pumps.

3. Check the well for flow.

4. *(See item 1.3.2 above).* Close annular preventer.

5. Record the time required for the crew to react and conduct the drill on the IADC drilling report.

It is expected that steps 1-3 will take about 2 minutes.

Performance of the complete drill (steps 1-5) should take approximately 10 minutes.

1.3.4 Kick while Drilling (Off Bottom - Shut in Well)

When the bit has been tripped to the previous casing shoe, a further drill may be conducted which will result in the well being shut-in.

After tripping the bit to the shoe, the following procedure may be used as a guideline for this drill:-

- Stop tripping operations, install the top drive and start circulating.

- Having been instructed to do so by the Rig Superintendent/Toolpusher, the Driller is expected to take the following steps to shut-in the well:-

    1. Pull up until the tool joint clears the BOP's. (Space out in accordance with pre-recorded space out data).
    2. Shut down the pumps.
    3. *(See item 1.3.2).* Close the annular preventer.
    4. Check well is shut in.
    5. Record the casing and drill pipe pressure.
    6. Notify Rig Superintendent/Toolpusher the well has been shut in.
    7. Double check space out, close and lock hang-off rams, hang-off pipe and open annular.
    8. Record the time taken for the crew to shut-in the well on the IADC drilling report.

    Performance of the complete drill (steps 1-5) should take ± 10 minutes.

1.3.5 Choke Drill

The objective of this drill is to give drill crews the most realistic type of well control training and a feel for the equipment and procedures which they would use to kill a well.

This drill should be carried out prior to drilling out the intermediate and production casing strings. It should never be carried out when open hole sections are exposed. The following procedure is recommended:-

1. Run in hole and tag the top of cement.
2. Pull back one stand and install the top drive.
3. Break circulation and establish slow circulating rate pressures. (Consider circulating bottoms up prior to this if the annulus may contain contaminated mud).
4. Carry out standard BOP drill (kick while drilling), resulting in the well being shut-in.
5. Consider applying low pressure to the casing (typically 200psi), bring the pump up to kill speed controlling the drill pipe pressure according to a predetermined schedule.

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A drill pipe pressure schedule should be drawn up before the drill takes place and carefully adhered to.

It is important that the choke operator develops a feel for the lag time between manipulation of the choke and its subsequent effect on the drill pipe pressure. The lag time should be recorded, so that it can be used for reference, should a kick be taken in the next hole section.

It is important that this opportunity to circulate across a choke is used to maximum effect.

Note: Ensure mud pump pressure relief valves are set well below casing burst pressure before exercise takes place and re-set after exercise is complete.

1.3.6 Diverter Drill

Due to the historic unreliability of diverter systems it has become the Company's policy that "Shallow Gas" kicks, once the marine riser and BOP have been run, **WILL BE SHUT IN.** Despite this fact, since all the Company's installations are fitted with a diverter system, the following comments are included:-

- The objective of this drill is to minimise the Driller and drill crew's reaction time, while ensuring that all the diverter system and equipment is in good working order.
- The time taken for each diverter function to operate should be recorded.
- A drill should be carried out prior to drilling out of the surface casing.
- Rig specific shallow gas procedures are covered in the Company Emergency Response Manual and, if required by a particular contract, bridging documents.
- Diverter drills should be designed in line with the relevant Rig specific procedure, which will be adopted in the event of a shallow gas kick, and be held as part of the broader shallow gas drills that are usually held before spudding in.

1.3.7 Stripping Drill

The objective of this drill is to give drill crews the most realistic type of well control training and a feel for the equipment and procedures which they would use to strip into a well under pressure.

This drill should be carried out prior to drilling out the intermediate and production casing strings. It should never be carried out when open hole sections are exposed. The following procedure is recommended:-

1. Run in hole and tag the top of cement.

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2. Pull back several stands and install a "Gray" valve or some other non-return valve.

3. Break circulation and establish slow circulating rate pressures. (Consider circulating bottoms up, prior to this, if the annulus may contain contaminated mud).

4. Carry out standard BOP drill (kick while tripping), resulting in the well being shut-in.

5. Apply low pressure to the casing (typically 200 - 400psi).

6. Strip into the well through the upper annular, bleeding off specified volume of fluid after each stand, to bring the annulus pressure back the pressure applied in step 5.

7. Pre-calculated stripping sheet should be available for comparison.

It is important that the choke operator develops a feel for bleeding off small volumes of fluid in to the stripping tank, and that as many operators as possible get a chance to train on the equipment, as this drill will not be performed often.

Note: Ensure mud pump pressure relief valves are set well below casing burst pressure before exercise takes place and re-set after exercise is complete.

1.3.8 Frequency of Drills

1.	Kick while Tripping [1] BOP Drill	Every Trip (once string is inside casing)
2.	Kick while Drilling [1]	Pit Drill Every Tour that includes drilling operations.
3.	Choke Drill [2]	After every suitable casing string is run and cemented.
4.	Diverter Drill [2]	After surface casing - Once per well.
5.	Stripping Drill [2]	As agreed with client, after suitable casing string is run and cemented.

[1] **The drills are to involve Mud Loggers.**
[2] **These drills will be held with the Operator's Representative in attendance.**

All drills to be recorded in the IADC report with times included for items 1 & 2.

1.4 PRE-RECORDED INFORMATION

In order to initiate proper well control procedures quickly and effectively, information must be assembled and organised prior to well control problems arising.

The following data is required:-

1. **M**aximum **A**llowable **C**asing **P**ressure.
2. Casing shoe depth. Both TVD & MD
3. Hole depth - **M**easured **D**epth.
4. Hole depth - **T**rue **V**ertical **D**epth.
5. Drill string capacity.
6. Annular capacity.
7. **S**low **C**irculating **R**ates/pressures.
8. Pump displacement.
9. Mud weight.
10. Casing OD, ID, Grade and Burst Pressure
11. Choke line capacity.
12. Choke line length.
13. **C**hoke **L**ine **F**riction.

For ease of organisation and use, several formats of "Well Control Kill Sheet" are available. The Company's version is in appendix B.

The pre-recorded information will be updated at least every 24 hr. If there are rapid changes in critical values, the sheet will be updated more often.

1.4.1 <u>Leak off/Formation Integrity Tests</u>

Fracture Gradient

The fracture gradient reflects the minimum pressure at which a formation will rupture or existing fractures will be extended. The rupture or fracture pressure is usually expressed as a mud weight (in pounds per gallon) which will cause loss of circulation.

Generally, fracture gradients increase with depth. This usually means that the weakest part of the well is at the last casing seat. The best way to determine the fracture gradient is to run a "leak-off test" after casing is set and cemented. The pressure obtained from such a test can be used to determine how much back pressure can be held against this point during a well kill procedure (**M**aximum **A**llowable **C**asing **P**ressure).

This information is important and must be posted with maximum allowable annular press, for easy access along with other pre-recorded information.

Conducting Leak off/Formation integrity tests

Different techniques are available for running pressure integrity tests but, regardless of the method used, certain general points apply to all. For example, an accurate pressure

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gauge is required, a cementing pump (instead of the mud pump) is to be used, the pump rate should not exceed 1/4 bbl per minute (bpm) and, as previously mentioned, "new " hole below the casing shoe should be limited to 15 ft.

To conduct a formation integrity test, the recommended procedure is:-

1. Circulate the hole to establish a uniform mud density throughout the system.

2. Pull the bit into the casing shoe.

3. Rig up circulating head, secure same and pressure test lines.

4. Close the blowout preventer.

5. Using the cement pump, pump down the drill string at a rate of about 1/4 bpm.

6. On a graph, plot the fluid pumped in 1/4 bbl increments versus drill pipe pressure until the formation at the shoe starts to take fluid; at this point, the pressure will continue to rise, but at a slower rate.

7. Repeat the test to verify the point at which the formation just starts to take fluid - this point is leak-off pressure

Note: If a float is run in the string annulus pressure <u>must</u> be bled off through the choke prior to opening the annular preventer.

Leak off pressure (MACP) is converted to an "**E**quivalent **M**ud **W**eight"

1.4.2 <u>Slow Circulating Rate</u>

Slow Circulating Rate

Slow **C**irculating **R**ates, sometimes referred to as **S**low **P**ump **R**ates or **K**ill **R**ates are used as a reference point in well killing operations.

Circulating Pressure

Circulating pressure is the pump pressure required to overcome friction between the drilling fluid and whatever it contacts as it moves down the drill string, through the bit, and up the annulus.

Circulating pressure varies with mud properties (particularly mud weight, viscosity and cold Oil Based Muds), the length and size of the drill string, the size of nozzles in the drill bit, annular clearance and the rate of circulation.

To maintain valid readings, for slow circulating rate figures, it is necessary to take fresh readings whenever one of the parameters mentioned above changes.

Take new slow circulating rates with all pumps when one of the following happens:-

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1. Mud weight change of >0.1ppg. (Once new mud weight is even all the way around).

2. When back on bottom with a new bit. (Once bottoms up has passed).

3. When making rapid progress drilling.

4. Every 12 hours.

5. Following pump repairs.

Slow circulating rates will be taken with the pump, which would be used to kill the well, using the gauges that the pump operator and choke operator would be using during the kill operation.

Rates will be as agreed with the Rig Superintendent and may be expressed either as a pump speed, (e.g., 20 strokes per minute) or a flow rate, (e.g., 1 bbl/min).

SCR results will be recorded in an agreed place for the Driller's ready use with the most recent reading used in the daily update of the "Well Control Kill Sheet". SCR results should also be recorded on the IADC report.

1.4.3 Choke Line Friction

An effect of using small diameter choke and kill lines to handle high pressure fluids is the increased pressure required to move the fluids through the smaller lines due to increased friction.

This choke line friction pressure does not show up on the choke gauge but does have an effect on the wellbore. Because this pressure from choke line friction (CLF) is felt downhole by the wellbore, allowance for it must be made during a kill circulation.

Ignoring CLF during pump start up, when the choke gauge is used instead of the drill pipe pressure gauge, will put additional pressure on the well equal to the CLF. This additional pressure could lead to breakdown of the casing shoe or formation.

Choke line friction increases with:-

1. An increase in choke line length.
2. An increase in mud weight and/or viscosity.
3. An increase in pumping rate.
4. With a decrease in choke line inside diameter.

In deep water, due to the long choke line lengths, this pressure can easily exceed the equivalent of ½ ppg mud weight at slow pump rates.

Knowing choke line friction and understanding its relationship to bottom hole pressure is the most important difference between "Normal" and "Deep Water" well control.

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Ignoring the effects of choke line friction can lead to a loss of well control either by allowing additional influx of formation fluids or by breakdown of the casing shoe or formation.

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1.4.4 Methods for Measuring Choke Line Friction Pressure (CLFP)

At least three slow circulating rates must be taken in two steps:-

Basic Method:-

1. Pump at the desired rate down the drill string, up the annulus.
   Record the rates and circulating pressures (example 200psi @ 30spm).

2. Pump, at the same rates as in step 1, down the drill string and up annulus against a closed BOP and up the choke line to poor boy degasser.
   Record the rates and circulating pressures (example 300psi @ 30spm).

CLFP is the pressure to circulate through the choke and/or kill line minus the pressure to circulate through the hole, i.e., 100psi @ 30spm (2 - 1)

Alternate Method:-

1. Pump down choke line and up the riser. Record the rates and circulating pressure.

2. Pump down choke line and up kill line. Record the rates and circulating pressure.

The CLP at a given rate would be the pressure difference between the recordings for the rates in 1 and 2.

Because CLF acts on the well but does not show up on the casing pressure gauge, allowance for it must be made during pump start-up.

2.0 PREVENTION

2.1 RESPONSIBILITIES

2.1.1 Offshore Installation Manager (OIM)

The OIM has the responsibility of ensuring that all operations onboard the installation are carried out according to agreed plans and procedures and measures to guard against loss of primary well control are implemented at all times.

The OIM will rely on the Rig Superintendent/Toolpusher and Operator's Representative(s), as drilling professionals, to guide him in his final decision making.

2.1.2 Rig Superintendent/Toolpusher

The Rig Superintendent/Toolpusher is responsible to the OIM for the safe, efficient, and cost effective management of drilling operations onboard the installation.

The Rig Superintendent/Toolpusher has the responsibility of planning, directing, and controlling drilling operations to ensure that they are conducted in as safe a manner as is reasonably practicable. In particular, the Rig Superintendent/Toolpusher is responsible for supervising the maintenance of primary well control by the constant monitoring of drilling fluid properties, fluid volumes and return flow rates so that imminent or actual loss of primary well control is prevented, or minimised and contained.

2.1.3 Bargemaster

The Bargemaster, as manager of marine operations onboard the installation, has the responsibility of cooperating with the Rig Superintendent/Toolpusher in planning to prevent loss of primary well control. His responsibilities will be mainly concerned with logistics, weather forecasting and ensuring that the marine crew are exercised in their well control functions.

2.1.4 Driller and Drill Crew

The Driller, as the person in direct control of drilling operations, has the responsibility for the maintenance of primary well control by the constant monitoring of drilling fluid properties, hole conditions, fluid volumes and return flow rates so that imminent or actual loss of primary well control is prevented, contained or mitigated. He must immediately inform the Rig Superintendent/Toolpusher on duty of any concerns he has about the conduct of operations. He must act on his own initiative, to shut the well in and thus minimise any influx, if he suspects that primary well control has been compromised for any reason.

As the supervisor of the Drill Crew, the Driller must ensure that all members of the crew are competent and exercised in the performance of the well control functions that may be required of them.

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The Driller has the responsibility, at all times that well operations are in progress, of remaining on the drill floor within immediate reach of the BOP operating panel and the well fluid monitoring equipment. He may not leave unless relieved by a competent person, to whom he has passed control of well operations by means of a detailed hand over.

2.1.5 Operator's Representative

The Operator's Representative has the responsibility of cooperating with the OIM and the Rig Superintendent/Toolpusher in planning drilling operations to ensure that they are conducted in as safe a manner as is reasonably practicable.

2.1.6 Third Party Employees

Certain Third Party employees have a vital function in monitoring the parameters that will announce an imminent or actual loss of primary well control. Mud Engineers, Cementers and Mud Loggers must be included in any well control planning and instructed in the actions that will be required of them.

2.2 PLANNING

2.2.1 Well Planning

Although most well planning will have been completed in advance of the drilling contract, Operations Managers and Superintendents, or someone appointed by them, will review the drilling contract and each well plan as early as possible in the plan's development. It is the OIM's responsibility, with the Rig Superintendent/Toolpusher's assistance, to review the terms of the drilling contract and each well plan, to ensure that they, the installation and the crew are capable of safely and efficiently providing the required service. Any concerns arising from this review which cannot be resolved with the onboard Operator's Representative must be immediately communicated to the Operations Manager for discussion with the Operator's Drilling Superintendent.

2.2.2 Casing Design

The Rig Superintendent/Toolpusher and the Operator's Representative must review the well plan to satisfy themselves that the rig has the capacity to meet the requirements of the approved casing design and setting depths.

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2.3 PRIMARY WELL CONTROL

2.3.1 The Drilling (or Completion) Fluid

To maintain hydrostatic well control, the fluid in the well bore must be of sufficient density to contain formation pressure.

All well operations conducted from the Company's installations are designed, planned and conducted to maintain, wherever possible, hydrostatic or primary well control. To this end, all installations will have a system for the regular monitoring and recording, of drilling or completion fluid properties. The monitoring system must also include the sampling and reporting frequency when circulation of fluid is not in progress. All those concerned in the maintenance of drilling and completion fluids will have access to this system and it must be subject to regular cross checking by re-calibration of instruments or use of different instruments at regular intervals.

2.3.2 Control of Lost Circulation

Lost circulation, with the consequent possible loss of hydrostatic pressure must be taken into consideration in well planning and clear instructions for immediate action included in the well plan.

2.3.3 Use of Pit Volume Totaliser (PVT)

PVT equipment, here taken to mean actual pit volume monitoring, trip tank volume monitoring whether mechanical, sonic or electronic, return flow indicators and pump stroke counters will be used at all times to monitor well conditions. The Mud Logger's systems, if available, will be used as an independent cross reference to the installation's own system.

2.4 PREVENTATIVE PROCEDURES

Three causes of kicks, considered among the most common, are avoidable. Rig specific procedures are developed to ensure that all measures necessary to avoid causing the following problems have been developed.

2.4.1 Failure to Keep the Hole Full

Failure to either keep the hole full, or ensure that the right amount of fluid is pumped into the hole to replace the volume of steel pulled from the hole, is an avoidable cause of well control problems. Pre-calculated hole fill schedules and accurate hole fill records will help to alert Drillers and Drilling Supervisors to problems.

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2.4.2 Swabbing

Failure to observe "good oilfield practice", such as reduced pipe pulling speeds in open hole, short trips before pulling out of the hole, and maintaining a good record of fluid volumes pumped into the hole to replace steel removed from the hole, can all lead to swabbing becoming a serious well control problem. Calculations on the effects of pumping a slug should always be made before pumping a slug and a slug should always be given time to find its own level before the trip begins.

2.4.3 Surging

Failure to observe "good oilfield practice", in this case, the use of the trip tank and pipe speed regulated with regard to hole condition and fluid properties can lead to surge pressures sufficient to cause lost circulation, loss of hydrostatic pressure and consequent well control problems. Pre-calculated hole fill schedules and accurate hole fill records will help to alert Drillers and Drilling Supervisors to problems.

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3.0 WARNING SIGNS

3.1 RESPONSIBILITIES

3.1.1 Offshore Installation Manager (OIM)

The OIM has the responsibility of ensuring that those he appoints to positions with a well control function are competent to fulfil that function, have received the training required by Government regulation and the Company training matrix and have been made aware, through instruction and exercise, of the actions required of them.

3.1.2 Rig Superintendent/Toolpusher

The Rig Superintendent/Toolpusher, as person in charge of drilling operations, has the responsibility of managing drilling operations onboard the installation and keeping the OIM informed of general progress. In particular, it is his duty to keep the OIM informed and advised of matters, such as well control problems, which might affect the safety of personnel or the installation.

It is the Rig Superintendent's/Toolpusher's responsibility to ensure that he, and the Drillers and Drill Crews that he supervises, are competent to recognise the warnings of possible well control problems and actual well control problems when they occur. He is responsible for ensuring that they have all received the required training and exercise to become capable and confident in recognising and dealing with any well control problems that may occur.

3.1.3 Driller and Drill Crew

The Driller is responsible for recognising well control problems and taking immediate action to contain, and thus minimise, the ingress of any undesired formation fluid into a well bore.

It is the Driller's responsibility to ensure that he and his crew are practiced in the actions necessary to shut in a well.

3.1.4 Operator's Representative

The Operator's Representative is responsible to the OIM for providing specialist well control advice with, if available, detailed knowledge of the specific area of operation.

3.1.5 Third Party Employees

Some Third Party Employees have well control functions. In particular the Mud Engineer and the Mud Logging crew, because of their involvement with drilling fluid monitoring, have a responsibility to alert the Driller and Rig Drilling Supervisors to any changes that they observe.

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3.1.6 General

When drilling with returns to surface, a kick cannot occur without warning signs. This section outlines and explains the signs, which indicate either that a kick has occurred or that a kick may soon develop.

3.2 DRILLING BREAK

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

Many factors influence the rate of penetration, but an increase in penetration rate can be caused by an increase in formation porosity, permeability or pore pressure. A change in all or one of these formation parameters may create the conditions in which a kick could occur.

For this reason any drilling break should be checked for flow.

Even if the flow check indicates no flow, the reason for each drilling break should be determined.

As an example, a drilling break could be caused by drilling into an impermeable transition zone above a permeable reservoir. Because the formation is impermeable, it is unlikely that any significant flow would be noticed during a flow check. However, the formation may be considerably under-balanced by the mud column. If drilling continued and the reservoir was penetrated, a kick may be taken.

Consideration must therefore be given to circulating bottoms up before drilling ahead after a negative flow check, especially in critical sections of the well.

3.3 INCREASED RETURNS FLOW RATE

The first confirmation that a kick is occurring is an increase in the flow rate returns while the pumps are running at constant output.

This increase may not, however, be detected if the influx flow rate is particularly slow. In this case, a slight pit gain may be the first detectable confirmation of the kick.

If low gravity formation fluid enters the wellbore during drilling, the hydrostatic pressure in the annulus will decrease rapidly with further influx and when the influx expands as it is circulated up the hole. As a result, rapid influx flow rates can quickly develop, even though the initial influx flow rate might have been very low.

The length of formation exposed also has direct bearing on the rate of flow into the well. The greater the length of formation exposed, the larger the flow rate.

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It is therefore important that surface equipment be able to reliably detect a small increase in returns flow rate.

3.4 PIT GAIN

3.4.1 Pit Gain - While Drilling

A gain in pit volume, which was not caused by the movement of mud stocks at surface, is confirmation that a kick is occurring or has occurred.

This is the most reliable indicator of a kick. Consequently, every effort must be made to ensure that pit levels are accurately monitored at all times.

Very small influx volumes may not be detected at surface as they occur. This may be due to the fact that either the initial influx was particularly small, or the influx flow rate was very slow. This could be the case if the formation has low permeability or if a more permeable formation was only very slightly under-balanced. In such cases, the influx may be detected before it is circulated to the surface if it expands significantly as it rises up the hole. In general, the greater the amount of gas that is contained in the influx, the greater the expansion of the influx will be as it rises up the hole.

As a result, the greater the proportion of gas in the influx, the more likely it is that the influx will be detected as it is circulated up the hole.

Consequently, a low volume influx of heavy oil or brine that does not contain any appreciable quantity of gas, will be relatively difficult to detect at surface.

However, if the active system is accurately monitored, pit gains of less than 10 bbl should be detected reliably, even on floating Rigs.

3.4.2 Pit Gain - During a Connection

An influx may occur during a connection due to the reduction in bottom hole pressure as the pumps are shut down and the pipe pulled off bottom.

If the well flows only during a connection, it is likely that the influx flow rate will be slow initially, resulting in only a small pit gain. Therefore, early detection of flow during a connection may be difficult.

However, it is important to check for flow during a connection, because if a close to balance situation is developing, it is most likely to show at this time. The first signs are likely to be increasing connection gases. However, if the under-balance develops very rapidly and the bottoms up time is considerable, then it is possible that an influx may occur before the connection gases are detected at surface. In this instance, flow during a connection may be the first indication of an under-balanced situation.

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The detection of a small pit gain during a connection is complicated by the volume of mud in the flow-line returning to the pit after the pumps have been shut down. This will cause an increase in pit level during each connection.

It is important therefore, to establish the volume of mud that is contained in the flow-line during circulation. For instance, this volume might be 10 bbl and as such, a 10 bbl pit gain during a connection would not be significant. However, a 15 bbl gain may indicate that a 5 bbl influx has occurred.

If there is any concern felt about the possibility of an influx during a connection, particularly while drilling in a suspected gas or oil reservoir zone, the hole will be lined up to the trip tank, for more precise return flow metering, while the connection is made.

3.5 GAS CUT MUD

A kick is confirmed at surface by an increase in the flow rate of returns and a pit gain.

However, a minor influx that is not detected as a pit gain may first be identified at surface in the returned mud. Formation fluids and gas in the returned mud may therefore, indicate that a low volume influx is occurring or has occurred, even though no gain has been detected.

Returned mud must be monitored for contamination with formation fluids. This is done by constantly recording the flow-line mud density and accurately monitoring gas levels in the returned mud.

Gas cut mud does not in itself indicate that the well is kicking (gas may be entrained in the cuttings). However, it must be treated as early warning of a possible kick. Therefore, the pit level should be closely monitored if significant levels of gas are detected in the mud.

An essential part of interpreting the level of gas in the mud is the understanding of the conditions in which the gas entered the mud in the first place.

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

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

Gas due to one or a combination of the above, is classified as follows:-

3.5.1 Drilled Gas

As porous formations containing gas are drilled, it is inevitable that a certain quantity of the gas contained in the cuttings will enter the mud.

Any gas that enters the mud, unless in solution with oil base mud and above the bubble point, will expand as it is circulated up the hole, causing gas cutting at the flow-line.

Gas cutting, due to this process, will occur even if the formation is overbalanced. Raising the mud weight will not prevent it. However, drilled gas will only be evident during the time taken to circulate out the cuttings from the porous formation.

3.5.2 Connection Gas

Connection gases are detected at surface as a distinct increase above background gas, as the hole is circulated bottoms up after a connection.

Connection gases are caused by the temporary reduction in effective total pressure of the mud column during a connection. This is due to pump shut down and the swabbing action of the pipe.

In all cases, connection gases indicate a condition of near balance. Consequently, when connection gases are identified, consideration should be given to weighting up the mud before drilling ahead and particularly prior to a trip.

3.5.3 Trip Gas

Trip gas is any gas that entered the mud while the pipe was tripped and the hole appeared static. Trip gas will be detected in the mud on circulating bottoms up after a round trip.

If the static mud column is sufficient to balance the formation pressure, the trip gas is caused by swabbing and gas diffusion.

Significant trip gas may indicate that a close to balance situation exists in the hole.

3.5.4 Gas Due to Inadequate Mud Density

Surface indications of an under-balanced formation depend on the degree of under-balance, as well as the formation permeability.

The penetration of a permeable formation that is significantly under-balanced will cause an immediate pit gain.

A permeable formation that is only slightly under-balanced may only cause a small flow into the well. The first evidence of this at surface is likely to be gas cut mud, accompanied by a small pit gain. The initial pit gain may be so small that it is only detected as it expands as it is circulated up the hole.

In the case where a tight formation is under-balanced, there may be little or no actual flow of gas into the wellbore. Therefore, drilling such a formation may show only gas cut mud, even if the under-balance is relatively high. This is a relatively difficult situation to detect and is also potentially dangerous.

3.6 CHANGE IN PUMP SPEED OR PRESSURE

Pump pressure may decrease with a corresponding increase in pump speed if an influx occurs during drilling.

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This indication is caused as a result of the U-tube effect, caused by light fluids flowing into the annulus. However, it is only likely to become noticeable as the influx is circulated up the hole.

A washout in the drillstring will cause the same decrease in pump pressure and increase in pump speed. However, if these signs are noticed, the Driller should first assume that a kick may have occurred and flow-check the well.

3.7 INCORRECT HOLE FILL DURING TRIP

As pipe is pulled from the hole, it is essential that the appropriate volume of mud is used to keep the hole full. This is essential in order that both a full column of mud is maintained in the hole and that if an influx is swabbed into the hole, it is detected immediately.

Before every trip, a trip sheet *(See Appendix C)* should be filled out. This must clearly show the expected hole fill volumes as the pipe is pulled out of the hole. As the trip proceeds, actual hole fill volumes should be entered in the trip sheet alongside the expected volumes. If the hole takes less mud than expected, this should be taken as positive indication that an influx has been swabbed into the hole.

A flow-check should be carried out immediately or, if in a reservoir section, the well should immediately be shut in.

A negative flow-check at this point is not necessarily confirmation that an influx has not occurred. It is quite possible, even if an influx has been swabbed into the well, that the well will not flow if the pipe is stationary.

Therefore, if at any stage in a trip, the hole does not take the correct volume of mud, the pipe should be run or stripped back to bottom, using the trip tank/stripping tank, and bottoms up circulated.

The problems associated with dealing with a kick when the pipe is off bottom can be considerable, and so every effort must be made to ensure that significant swab pressures are avoided during a trip.

The risk of swabbing can be minimised by ensuring that the mud is in good condition prior to pulling out of the hole and ensuring that pre-determined pipe pulling speeds are not exceeded at any stage in the trip.

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4.0 ACTION ON DETECTING INFLUX

4.1 RESPONSIBILITIES

4.1.1 Offshore Installation Manager (OIM)

The OIM has the responsibility of ensuring that those he appoints to positions with a well control function are competent to fulfil that function, have received the training required by government regulation and the Company training matrix, and have been made aware, through instruction and exercise, of the actions required of them.

Prior to spudding in a well, it is the OIM's responsibility to ensure that the Rig Superintendent/Toolpusher and the Operator's Representative have investigated the possibility of encountering shallow gas, made a contingency plan to cater for the eventuality and implemented shallow gas procedures.

4.1.2 Rig Superintendent/Toolpusher

The Rig Superintendent/Toolpusher, as the person with the responsibility of managing the drilling operations onboard the installation, is responsible for keeping the OIM informed of general progress. In particular, it is his duty to keep the OIM informed and advised of matters such as well control problems, which might affect the safety of personnel or the installation.

It is the Rig Superintendent/Toolpusher's responsibility to ensure that both he and the Drillers and Drill Crews that he supervises, are competent to recognise well control problems when they occur. He is responsible for ensuring that they have all received the required training and exercises to become capable, confident and competent in recognising and dealing with any well control problems which may occur.

Before spudding in a well it is the Toolpusher's responsibility to liaise with the Operator's Representative in directing the development of a shallow gas contingency plan.

4.1.3 Bargemaster

The Bargemaster, as the person in charge of the marine operations on the installation, has the responsibility of cooperating in the development of the installation's well control plan. He will be involved in the preparation of the installation's shallow gas and other contingency plans, and in the implementation of shallow gas precautions. He has particular responsibility for any contingency plans that involve moving the installation off location.

In any well control situation the Bargemaster will have particular responsibility for logistics forward planning and weather forecasting. It will be his responsibility to monitor, present and forecast weather conditions and advise the OIM and Rig Superintendent/Toolpusher on predicted vessel motion and evacuation capabilities.

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4.1.4 Driller and Drill Crew

The Driller is responsible for recognising well control problems and taking immediate action to contain, and thus minimise, the ingress of any formation fluid into a well bore.

It is the Driller's responsibility to ensure that he and his crew are practiced in the actions necessary to shut in a well.

It is the Driller's responsibility to ensure that he and his crew are familiar with and understand the actions that may be required of them.

4.1.5 Operator's Representative

The Operator's Representative is responsible to the OIM for providing specialist well control advice with, if available, detailed knowledge of the specific area of operation.

Prior to spudding-in, it is the Operator's Representative's responsibility to cooperate with the Rig Superintendent/Toolpusher and the OIM in developing a shallow gas contingency plan, as an addition to the Rig's overall well control plan.

4.1.6 Third Party Employees

Those Third Party Employees with well control functions may, if required, be called upon to assist in the development, or implementation, of the shallow gas contingency plan as an addition to the Rig's overall well control plan.

The following positions, and any others required by the OIM, are normally involved in formulation of the well control plan and, if necessary, the plan's execution:-

- Cementer
- Mud Engineer
- Mud Logging Supervisor

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4.2 SHALLOW GAS

4.2.1 Shallow Gas Precautions

Shallow gas kicks are generally caused by loss of hydrostatic head, due to one or a combination of the following:-

- Overloading the annulus with cuttings and hence causing losses.
- Drilled gas expanding and unloading the annulus.
- Improper hole fill while tripping.

The following precautions will minimise the possibility of inducing a shallow gas flow:-

- Drill pilot hole
- Drill riserless
- Restrict BOP's

Accurately monitor the hole.

4.2.2 Shallow Gas Procedures - Drilling With Riser

IT IS NOT COMPANY POLICY TO USE A RISER WHEN DRILLING FOR THE SURFACE CASING. IF FOR ANY REASON A PIN CONNECTOR IS TO BE USED, AN ANNULAR PREVENTER AND SUBSEA DUMP VALVE ARE TO BE INSTALLED AT THE MUDLINE, IN ADDITION TO THE NORMAL DIVERTER SYSTEM AT SURFACE.

Industry experience has shown that current diverter systems cannot be relied upon to safely control shallow gas blowouts. As a result, shallow gas flows should be controlled at the seabed, using the subsea dump valves at the mudline and annular preventer.

Immediate preparations should then be made to unlatch the pin connector or LMRP and winch off location, up current but not down wind.

A contingency plan must be developed, prior to spud, in conjunction with the Operator's Representative to cover the following situations:-

- The procedures to be adopted in the event of a shallow gas flow.
- The procedure for winching the Rig off location.
- The procedure to be adopted in the event of failure of any of the major components of the BOP/riser/diverter system.

The contingency plan must be discussed in detail at the pre-spud meeting.

The surface diverter system ensures that there is a back-up system available in the event of a failure of the subsea system. It can also be used to divert gas that may be in the riser above the stack.

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The following precautions should be taken routinely whilst the surface hole is open:-

- ♦ The Rig should be moored with length of moorings remaining in the lockers to allow the Rig to be winched 400 ft away from the gas plume. If practical, the windlasses should be held on their brakes and the chain stoppers only applied after surface casing is set.

- ♦ All hatches should be secured to prevent invasion of voids by combustible gas or down flooding if the freeboard is reduced by loss of buoyancy or heel.

- ♦ Facilities and personnel should be continuously available at short notice to slack off the moorings closest to the plume and heave in those up current (but not down wind). Before spudding, a contingency plan should be prepared detailing individual responsibilities and duties.

- ♦ Care should be taken to ensure that the annulus does not become overloaded with cuttings, causing losses or cuttings liberated gas, and hence the possibility of unloading the annulus. This is achieved by drilling a pilot hole and/or limiting the ROP and circulating at a high rate to distribute the cuttings and drilled gas.

- ♦ Facilities should be continuously available to fill the annulus rapidly from surface in the event of sudden losses.

- ♦ Care should be taken to monitor the hole and ensure that it remains full whilst tripping.

- ♦ A float valve should always be run in the drillstring.

- ♦ Sufficient mud should be kept onsite to fill the hole volume twice.

Should the well start to flow, the following procedure can be used as a guideline:-

- Open the subsea dump valves.
- Close the annular preventer and allow the gas to vent at the seabed.

If there is no immediate danger to personnel or the Rig:-

- Attempt to control the well by pumping sea water/mud at a maximum rate.

If the gas flow is endangering personnel or the Rig:-

1. Consider dropping the drillstring.
2. Unlatch the LMRP or pin connector and winch the Rig to a safe position outside the gas plume.

In the event of failure of the subsea diverter system there remains the option of unlatching the LMRP or pin connector, thereby venting the gas at the wellhead.

Diverting at surface is not recommended, however, if it becomes absolutely necessary to divert at surface, proceed as follows:-

1. Maintain maximum pump rate.

2. Space out so that a tool joint is just above the rotary table.

3. Open the diverter lines, close the shaker valve and diverter element thereby diverting returns overboard.

4. Shut down all non-essential equipment and machinery to minimise potential sources of ignition. Deploy fire hoses beneath the Rig floor. Consider running drill floor deluge system.

5. Prepare to unlatch the pin connector or LMRP and winch installation to a safe position.

If the situation is deteriorating and loss of control is imminent:-

1. Consider dropping the drillstring.

2. Have a spare set of elevators ready to secure below tool joint and prepare to drop string. (Should be rehearsed before spud in).

3. Release the pin connector or LMRP and winch the Rig to a safe position outside the gas plume.

4.2.3 Shallow Gas Procedures - Drilling Without Riser

Drilling riserless ensures that the major cause of blowouts from shallow, normally pressured gas reservoirs, namely the loss of hydrostatic head, is eliminated. There remains however, the danger of penetrating an over-pressured reservoir.
A shallow gas contingency plan, developed by the installation's managers and the Operator's Representative, must be produced prior to spud-in. The plan must, as a minimum, cover the following:-

- The procedures to be adopted in the event of a shallow gas flow.
- The procedure for winching the Rig off location.

The contingency plan must be discussed in detail at the pre-spud meeting.

A gas blowout in open water typically produces a 10-degree cone of low-density water and a discharge of highly flammable gas. The intensity of the blowout depends, to a large extent, on the water depth and current. The plume is likely to become more dispersed with greater water depth, whilst the effect of a current would be to displace the plume away from the Rig.

Within a plume of expanding gas, a floating installation will suffer some loss of buoyancy, however, this diminishes rapidly with water depth such that the effect on a semi- submersible at operating draft would be negligible. Under calm conditions, the gas cloud would disperse slowly and would constitute a fire hazard if the gas became entrapped in a confined area.

The severity of the hazard can only be assessed at the time, and whilst there is unlikely to be an immediate danger to crew or installation, the following precautions or considerations should be addressed before and whilst the surface hole is open:-

- The Rig should be moored with length of moorings remaining in the locker to allow the Rig to be winched 400 ft away from the plume. If practical, the windlasses should be held on their brakes and the chain stoppers only applied after surface casing is set.

- All hatches should be secured to prevent invasion of voids by combustible gas or down flooding if the freeboard is reduced by loss of buoyancy or heel.

- Facilities and personnel should be continuously available at short notice to slack off the moorings closest to the plume and heave in those up current (but not down wind). Before spudding, a contingency plan should be prepared detailing individual responsibilities and duties.

- Drill pilot hole and/or limit the ROP and circulate at a high rate to distribute the cuttings and drilled gas.

- Personnel should be assigned to bubble watch and monitor SSTV.

A float valve should always be run in the drillstring.
Sufficient mud should be kept on site to fill the hole volume twice.

Weather conditions and current should be continuously monitored and the sea surface should be checked for evidence of gas.

Assigned winch operators should have VHF handsets immediately available throughout this hole section to minimise delay in starting winching off operations.

ROV (if available) or subsea TV should be utilised to watch the seabed for gas returns.

If a shallow gas flow is detected and if there is no immediate danger to personnel or the Rig:-

- Attempt to control the well by pumping mud/seawater at a maximum rate.

If the gas flow is endangering personnel or the Rig:-

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- Consider dropping the drillstring.
- Winch the Rig to a safe position outside the gas plume.

4.2.4 Drilling Below "Surface Casing"

Once conductor pipe (30" casing) and surface casing (20" casing) has been set, the BOP will normally be run. **Although surface casing is not normally considered "competent casing" for shutting in gas kicks, Company policy is to shut in kicks using this casing rather than having to rely on the surface diverter system.** This is a calculated decision in view of the thinking that an underground blowout is less of a hazard to personnel, to the installation and to the environment, than large quantities of combustible gas.

4.3 SHUT IN PROCEDURES - WHILE DRILLING

4.3.1 Kick While Drilling

Company policy is to use a "fast" shut in. *See "Kick while Drilling" flowchart WC - 01*

If any of the following occur:-

- ♦ Drilling break
- ♦ Increased return flowrate
- ♦ Pit gain
- ♦ Change in pump speed or pressure

STOP DRILLING!

- ♦ Pick up - position tool joint to a predetermined distance above rotary.
- ♦ Shut down mud pumps
- ♦ Flow check (if there is still doubt)
- ♦ *(See item 1.3.2).* Close upper annular preventer.
- ♦ Record pressures *****
- ♦ Notify Rig Superintendent/Toolpusher and Operator's Representative.
- ♦ Check space out and hang off on (to be stipulated) rams.

Record drill pipe and casing pressures every minute until there has been no change for five minutes then every five minutes until directed to do otherwise.

* (If float is run above the bit there will be no change in SIDPP once float shuts).

4.3.2 Massive Fluid Losses

If severe mud loss occurs during well operations, immediately attempt to fill the hole by pumping fluid into the annulus by whatever means is quickly available (if drilling keep

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pumping down the drill string, at a reduced rate, at the same time as pumping into the annulus).

The fluid used to fill, or attempt to fill, the annulus will be determined by:-

1. make of fluid in the hole, (i.e., oil or water based mud)
2. severity of loss
3. availability of compatible substitute fluid etc.

The important principle is to fill the hole and to keep it full and all endeavors should be made to achieve this. If nothing else is available or the hole will not support heavier fluid, salt water should be used to fill the hole.

Loss of fluid into a weak zone in the formation, with the resultant loss of hydrostatic pressure as the fluid level drops, may allow an influx of formation fluid into the well bore. The resultant underground blowout with formation fluids travelling from an over-pressured zone to an under-pressured or weak zone is one of the hardest and potentially most costly situations to correct. (For well control in underground blowout situations, see section 5.7.1)

It is very important that those people with well control responsibilities are aware of the potential dangers of lost circulation and do not lose sight of the implications and potential for well kicks, etc., while attempting to cure lost circulation.

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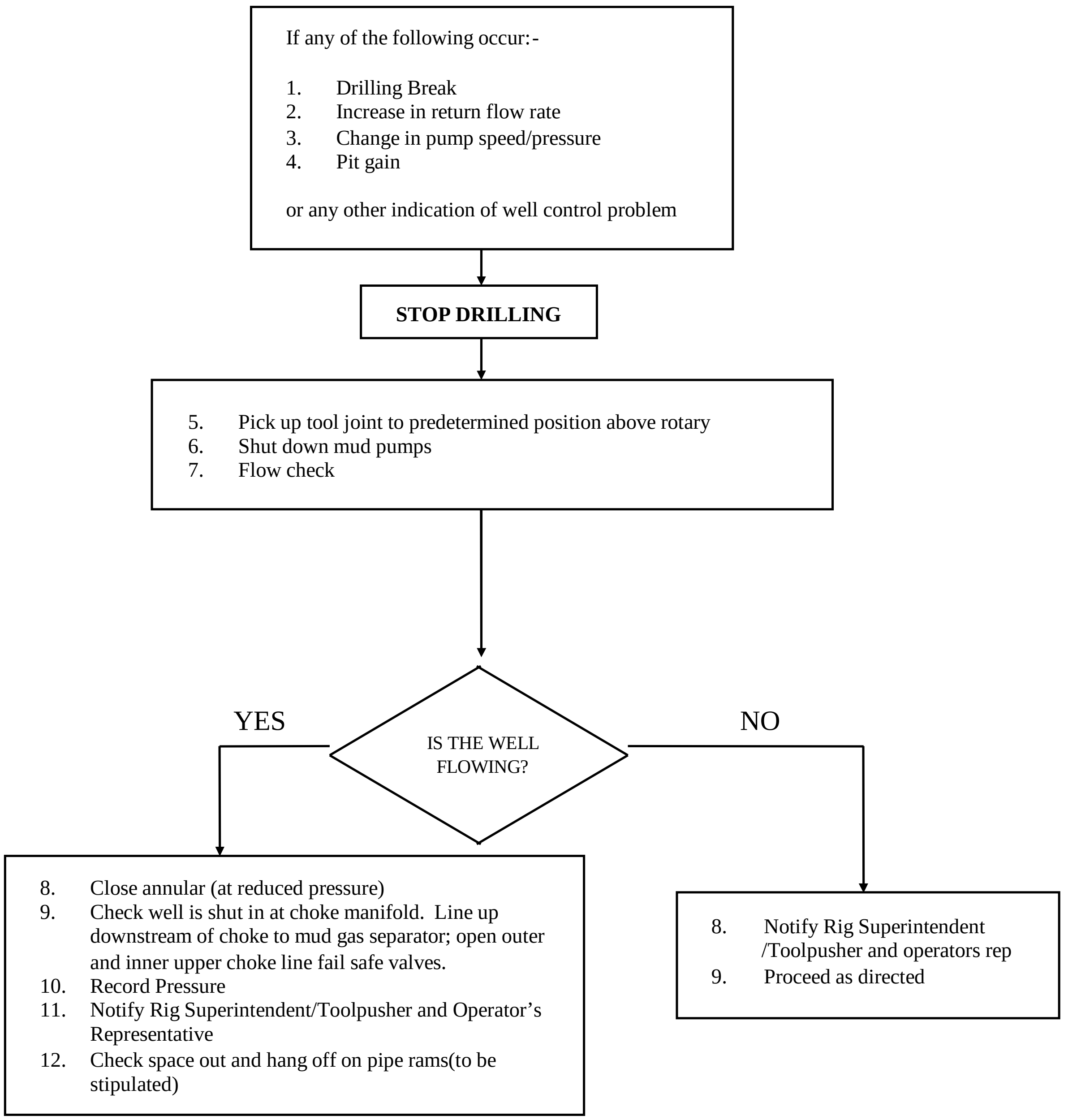
Flowchart: WC-01 Kick While Drilling (Fast Shut-in)

Instructions to the Driller

It is the Driller's responsibility to shut the well in quickly if it is flowing. He is authorised to flow check the well whenever he considers it necessary.



4.4 SHUT IN PROCEDURES - WHILE OFF BOTTOM

4.4.1 Kick While Tripping

Company policy is to use a "fast" shut in. *See "Kick while Tripping" flowchart WC - 02*

If any of the following occur:-

- ♦ Incorrect hole fill tally
- ♦ The well appears to be flowing

STOP TRIPPING!

- ♦ Flow Check

If the well is flowing:

- ♦ Set slips
- ♦ Install (open) safety valve and close
- ♦ Open outer and inner fail-safe valves and close upper annular
- ♦ Pick up stand of drill pipe and make up top drive
- ♦ Check well is shut in
- ♦ Notify Rig Superintendent/Toolpusher and Operator's Representative
- ♦ Line up standpipe manifold
- ♦ Record pressures *****
- ♦ Check space out, open DSC and hang off on rams *(preferably pipe rams)*

Record pressures every minute until there has been no change for five minutes then every five minutes until directed to do otherwise.

* (If a non-ported float is run above the bit there will be no change in SIDPP once float shuts)

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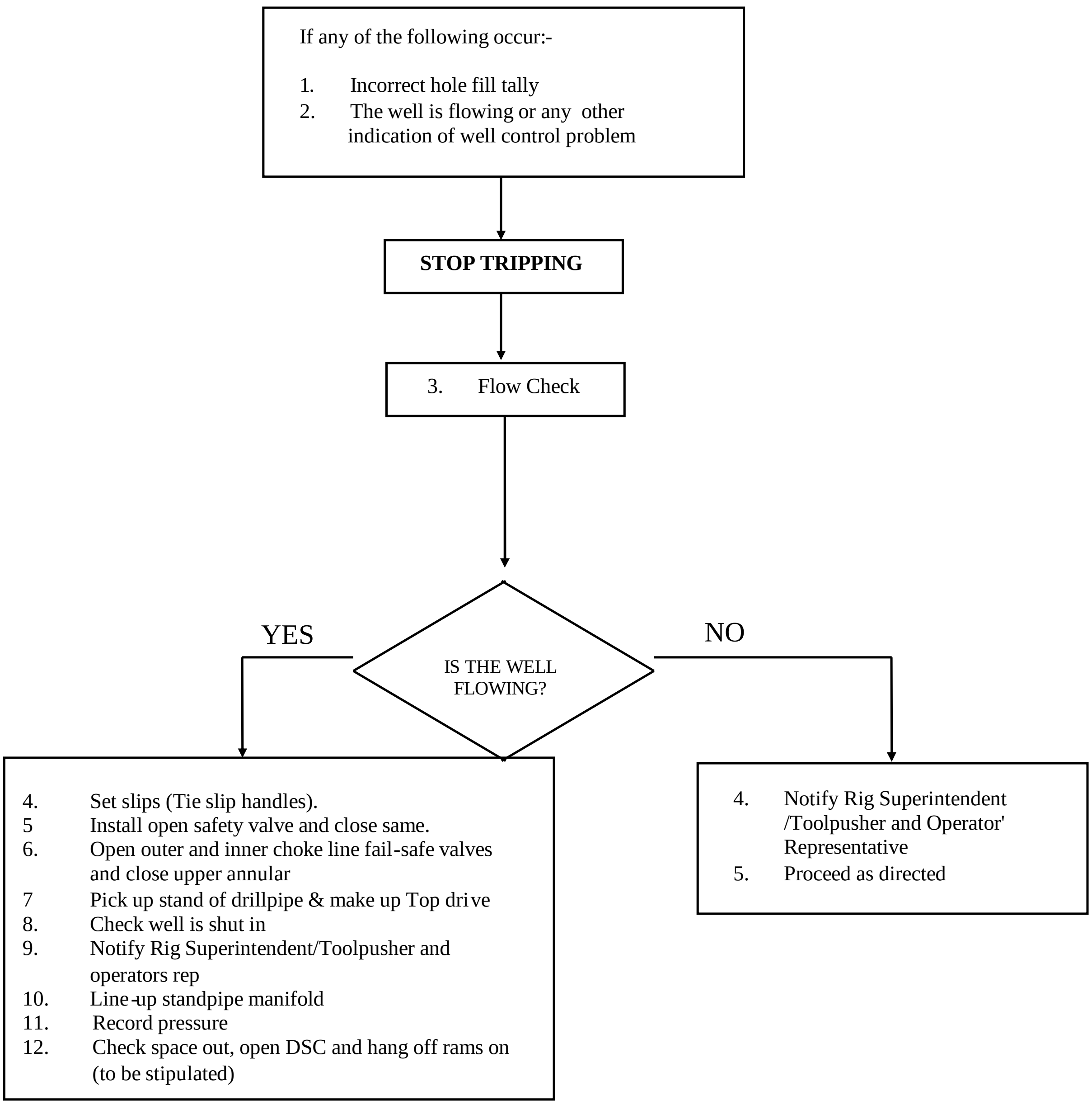
Flowchart: WC-02 Kick While Tripping

With Drillpipe in BOP and Top Drive in use

Instructions to the Driller

It is the Driller's responsibility to shut the well in quickly if it is flowing. He is authorised to flow check the well whenever he considers it necessary.



4.5 SHUT IN PROCEDURES - WHILE OUT OF THE HOLE

4.5.1 Kick While Out of the Hole

Company policy is to use a "hard" shut in. *See "Kick while out of the hole" flowchart WC - 03*

If any of the following occur:-

- Trip Tank Gain
- The well is flowing

Take the following action:-

- Close annular preventer (at reduced annular pressure).
  - 3a. Ensure choke/kill manifold is closed.
  - 3b. Open BOP upper outer, and inner choke valve.

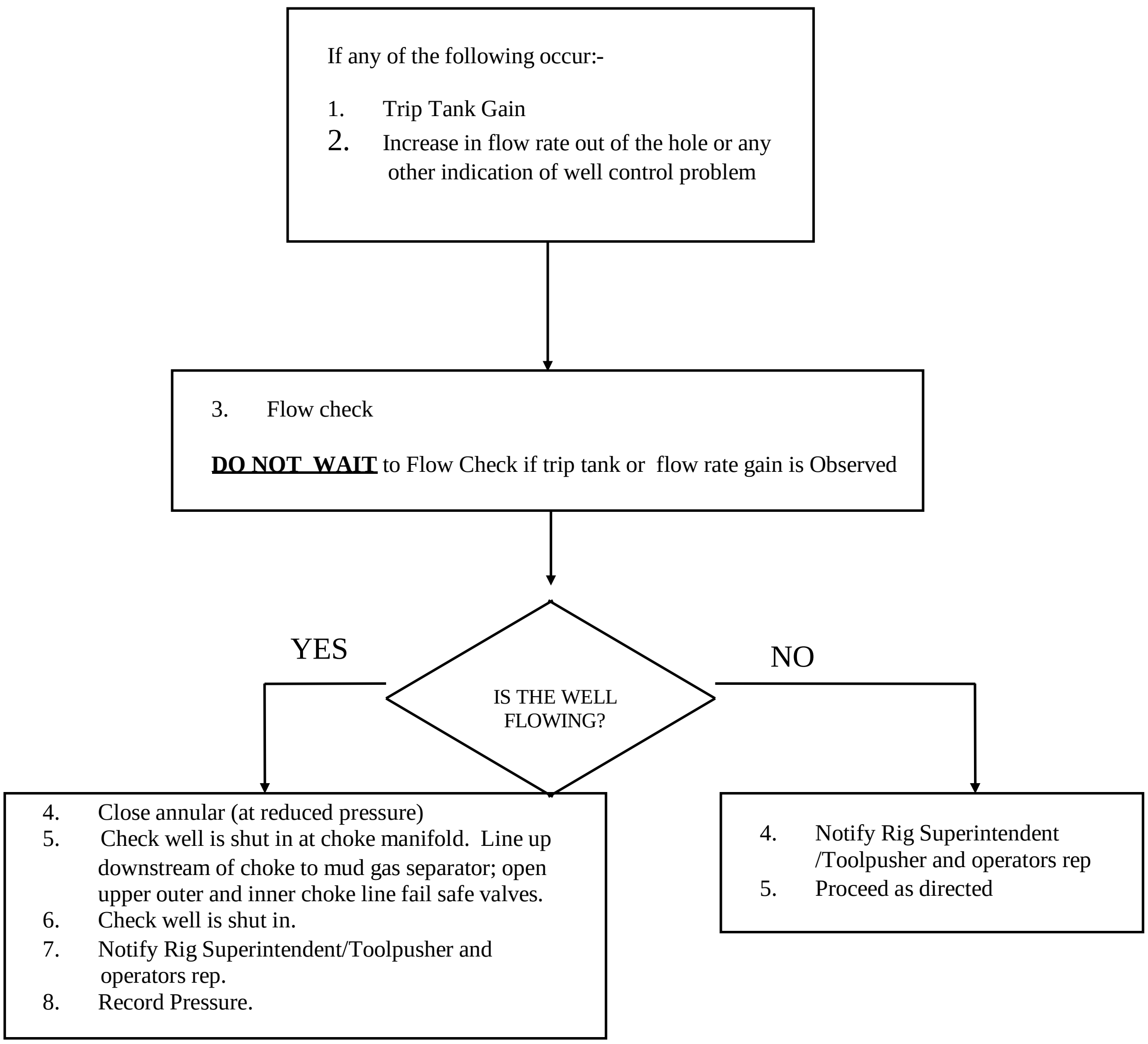
- Open outer and inner fail-safe valves
- Check well is shut in
- Notify Rig Superintendent/Toolpusher and Operator's Representative.
- Record pressures *****

* Record pressures every minute until there has been no change for five minutes then every five minutes until directed to do otherwise.

Flowchart: WC-03 Kick While Out of the Hole

Instructions to the Driller
The well will be monitored on the trip tank while out of the hole.

It is the lDriller’s responsibility to shut the well in quickly if it is flowing. He is authorised to flow check the well whenever he considers it necessary.



4.6 ACTIONS AFTER WELL IS SHUT IN

Once the Driller has shut the well in, checked to see that the BOP has functioned correctly, and informed the Operator's Representative and the Rig Superintendent/Toolpusher on tour, who will in turn inform the OIM, he is required to monitor the **S**hut **I**n **D**rill **P**ipe **P**ressure and the **S**hut **I**n **C**asing **P**ressure and record his observations. Readings should be taken and recorded every minute, until there has been no change for five minutes, and then every five minutes until pressures can be considered "stable". Once pressures have stabilised it is still necessary to keep observing and recording pressures, at interval to be specified by the Rig Superintendent/Toolpusher, as the records will give indications of gas migration or any other changes in the well conditions.

While the Driller is monitoring and recording pressures, the Rig Superintendent/Toolpusher is advised to have the Subsea Engineer check over the BOP control system to make sure everything is as it should be.

4.7 REPORTING WELL KICKS

As soon as reasonably practicable following a well kick, the “First Report of Well Kick” form in Section 4.7.1 is to be filled out and faxed to the local office. The local office will then forward the report to Houston.

Telephone communication should be made through the normal chain of command, following transmission of the fax.

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4.7.1 First Report of Well Kick Form

SEADRILL

FIRST REPORT OF WELL KICK

RIG NAME : ____________ DATE : ____________ TIME OF KICK : ____________

OIM : ____________ CO REP'S NAME : ____________

SIDP : ____________ psi SICP ____________

PIT GAIN BEFORE CLOSING IN BOP : ____________ bbls TOTAL PIT GAIN ____________

TRUE VERTICAL DEPTH : ____________ ft MEASURE DEPTH ____________

BIT DEPTH : ________ ft MWD DEPTH : ________ ft DP FLOAT : YES ☐ NO

CASING SIZE : ________ in BURST RATING : ________ psi DEPTH : ____________

LEAK-OFF TEST : ________ psi MUD WEIGHT (BEFORE KICK) : ____________ ppg

KILL WT. MUD : ________ ppg WEIGHT MATERIAL ONBOARD: ____________ sacks

ACTIVE SYSTEM VOLUME : ________ bbls MUD PUMP #1 SPR psi ________ SPM ________

MUD PUMP #2 SPR psi ________ SPM ________

MUD PUMP #3 SPR psi ________ SPM ________

BOP CONFIGURATIN (TOP DOWN)

Number of Annulars the BOP is equipped with (one/two) : ____________

RAM #1 ________ RAM #2 ________ RAM #3 ________ RAM #4 ________ RAM #5 ________

ANNULAR CLOSED #1 OR #2 : ____________ DP HUNG-OFF ON RAM # : ____________

SIGNIFICANT EQUIPMENT PROBLEMS : ____________

WELL PROBLEMS PRIOR TO KICK : ____________

OPERATIONS PRIOR TO KICK : ____________

WELL SHUT-IN BY : NAME: ____________ TITLE: ____________

REMARKS ....

REPORT SUBMITTED FROM RIG BY NAME : ____________ TITLE : ____________

REPORT RECEIVED BASED OFFICE BY NAME : ____________ TITLE : ____________

5.0 WELL CONTROL DECISION MAKING

5.1 RESPONSIBILITIES

5.1.1 Offshore Installation Manager (OIM)

The OIM has the final responsibility for well control. A Company OIM will be trained in well control, but as he is not necessarily a drilling professional, he will consult with the Rig Superintendent/Toolpusher, Operator's Representative and Rig Superintendent, to arrive at decisions on well control once a well control problem has occurred.

5.1.2 Rig Superintendent/Toolpusher

It is the Rig Superintendent/Toolpusher's responsibility, in consultation with the Operator's Representative, to advise the OIM on the well kill method that should be used. He has a duty to proceed with extreme caution and consider carefully all the implications of his advice and actions in any well control situation.

5.1.3 Barge master

The Bargemaster will be involved in well control decision making to advise on expected weather conditions, vessel motion, supply boat and helicopter logistics, and evacuation capabilities. He will make every effort to be as accurate as possible in these predictions, communicating with local weather centres as required.

5.1.4 Driller and Drill Crew

The Driller and the Drill Crew will conduct the well killing operation under the Rig Superintendent/Toolpusher's supervision. The capability and experience of a crew may have some bearing on well control decision making, so all crew members have, as at any other time, a responsibility to bring any concerns they may have about planned operations, equipment to be used or procedures to be followed, to the attention of their immediate supervisor, the Rig Superintendent/Toolpusher or OIM. All crew members who have a well control function, have a duty to alert their supervisor if they are in any way uncertain of the part they are to play in any planned operation. It will be all supervisors' responsibility to ensure that their crews understand what will be required of them in a well control operation.

5.1.5 Operator's Representative

The Operator's Representative, in consultation with the Rig Superintendent/ Toolpusher and his supervisors at the Operator's base, will advise the OIM on the well kill method that should be used. He has a duty to proceed with extreme caution and consider carefully the implications of his advice and actions in any well control situation.

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5.1.6 Third Party Employees

Third Party employees, such as the Mud Engineer and Mud Loggers, will be called on by the Operator's Representative, the Rig Superintendent/Toolpusher and the OIM to assist in well control decision making, according to their area of expertise. They have a responsibility to bring any concerns they may have about planned operations, equipment to be used or procedures to be followed to the attention of the Operator's Representative, the Rig Superintendent/Toolpusher or the OIM.

5.2 INTRODUCTION

This section of the manual is intended to provide guidelines to the decision making process in a variety of different situations in the event of a well control problem.

In reality, the specific conditions prevailing at the time that the problem occurs, will determine the best course of action to take in order to resolve the problem.

This section should not necessarily be used as a guide at the moment that a problem occurs, but it is anticipated that general familiarity with the analysis presented in this section will enable personnel to be better prepared to deal with well control problems.

5.3 PIPE ON BOTTOM

If a kick is taken with the pipe on bottom, the well should be shut in as soon as is safely possible.

Having established that the well is safely closed in, it will be necessary to decide on the most appropriate method of killing the well. This decision is the responsibility of the OIM (See 5.1).

Having decided on the most appropriate course of action, the OIM is responsible for ensuring that all involved personnel are made aware of the procedures that will be used to kill the well. This will be effected by Pre-kill Meetings, as set out in the installation's Well Control Plan.

These steps are applicable to any situation in which a kick is taken.

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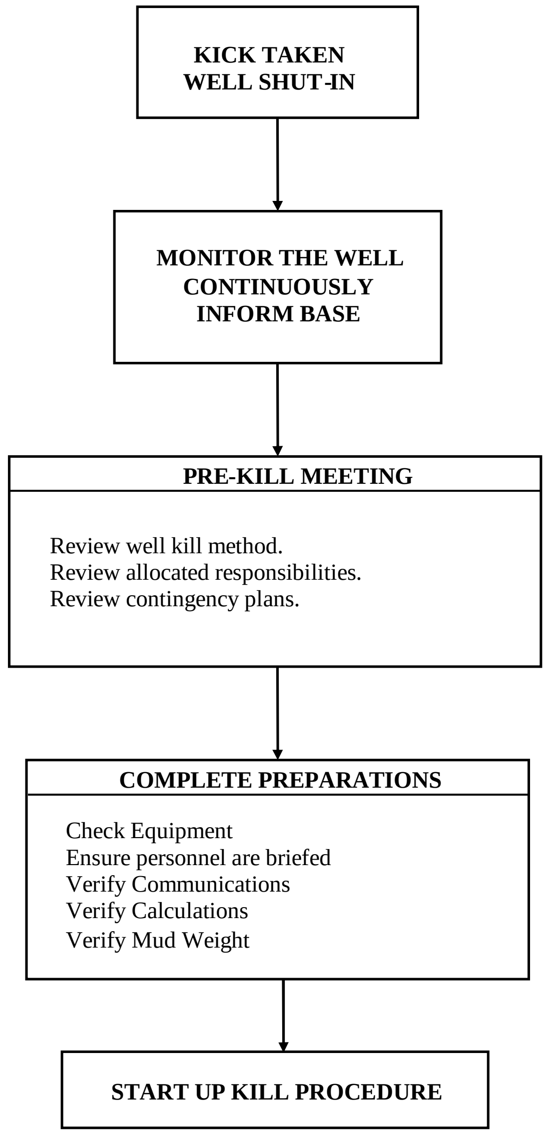
Flowchart: WC-04 Preparation for Well Killing Operation



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5.4 PIPE OFF BOTTOM

5.4.1 Pipe off Bottom (Drillpipe Through BOP)

If an influx is taken during a trip, it will generally be necessary to return the drillstring to bottom before a constant bottomhole pressure method can be used to kill the well.

The surface pressure will be a major factor in determining the most suitable method of returning the pipe to bottom. It must be considered in relation to the string weight and the pressure rating of the BOP's.

The first option that should be considered is stripping the pipe to bottom with the Rig equipment (See 5.5). Annular stripping is the most satisfactory method, however, ram combination stripping may have to be considered if surface pressures are approaching the pressure rating of the annular. On a floating Rig, ram combination stripping is a particularly difficult operation.

The pressure limitations imposed by the Rig BOP system may dictate that stripping the pipe to bottom is impractical. In this case, some means of reducing the pressure enough to allow stripping into the well must be implemented. (See Section 6 - Well Kill Techniques).

5.4.2 Pipe off Bottom (Drill Collars Through BOP)

Every effort should be made to ensure that well control problems are avoided when the BHA is through the BOP Regaining control from a situation in which a well control problem has occurred with the BHA through the BOP can present serious complications.

If a kick has been swabbed in, it may be possible to bring the well under control by bleeding gas and lubricating mud into the well. It is, however, undesirable to leave the collars in the stack for an extended period during a well control operation.

In any event, it is likely that the pipe will have to be stripped to bottom before the well can be killed.

There are considerable operational problems presented by attempting to strip a BHA through the annular preventer:-

- The BOP element will be subject to considerable stress as the spiral collars are stripped through it.
- Stabilisers in the BHA may prevent stripping completely.

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Further complications that may arise in this situation are numerous, but include the following:-

- There may not be sufficient weight of collars to strip through the annular BOP
- Well pressures may force the collars out of the hole.
- An internal blowout may occur through the drillstring.

The appropriate course of action required in these situations will depend to a large extent on the particular conditions and equipment on the installation.

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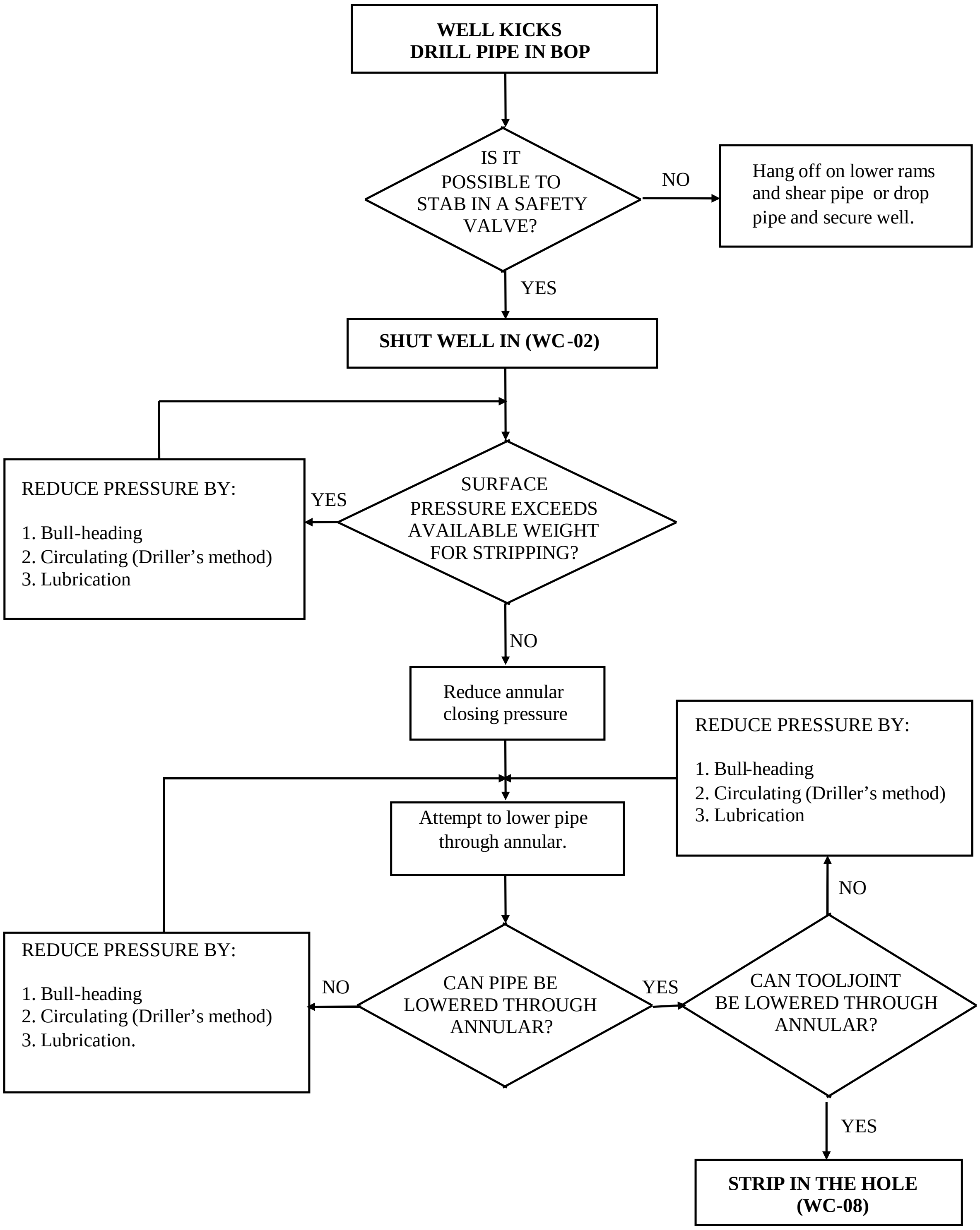
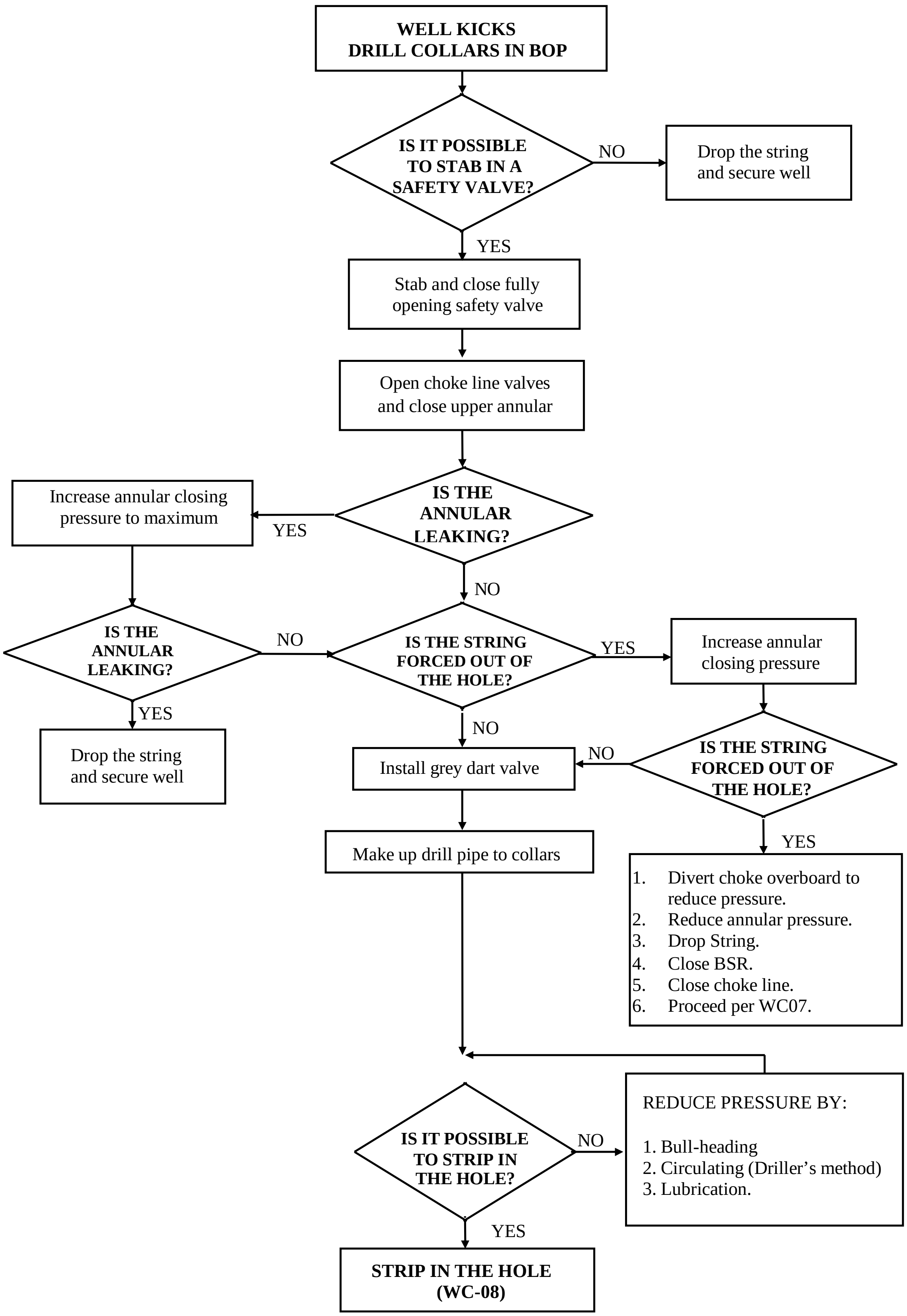
Flowchart: WC-05 Off Bottom - Drill Pipe Through BOP



Flowchart: WC-06 Off Bottom - Drill Collars Through BOP



5.4.3 No Pipe in the Hole

Correct tripping procedures will ensure that an influx is detected before the pipe is completely out of the hole.

Should an influx remain undetected during tripping and the well is shut in with no pipe in the hole, it may not be possible to re-introduce drillpipe into the hole in order to strip to bottom.

The limiting factor is the surface pressure in relation to the weight of the drillstring above the stack. A simple calculation will determine whether it will be possible to overcome the wellbore pressures with the weight of the string. The length of the riser limits the weight that can be applied at the BOP

If the influx is immediately below the stack, it may be possible to either kill the well by lubricating mud into the well, or to reduce the surface pressures such that it becomes possible to re-introduce pipe into the well.

However, if the influx is some way down the hole, it may not be possible to reduce the surface pressure significantly.

If the influx is migrating up the hole, it may be possible to kill the well by implementing the Volumetric Control Method.

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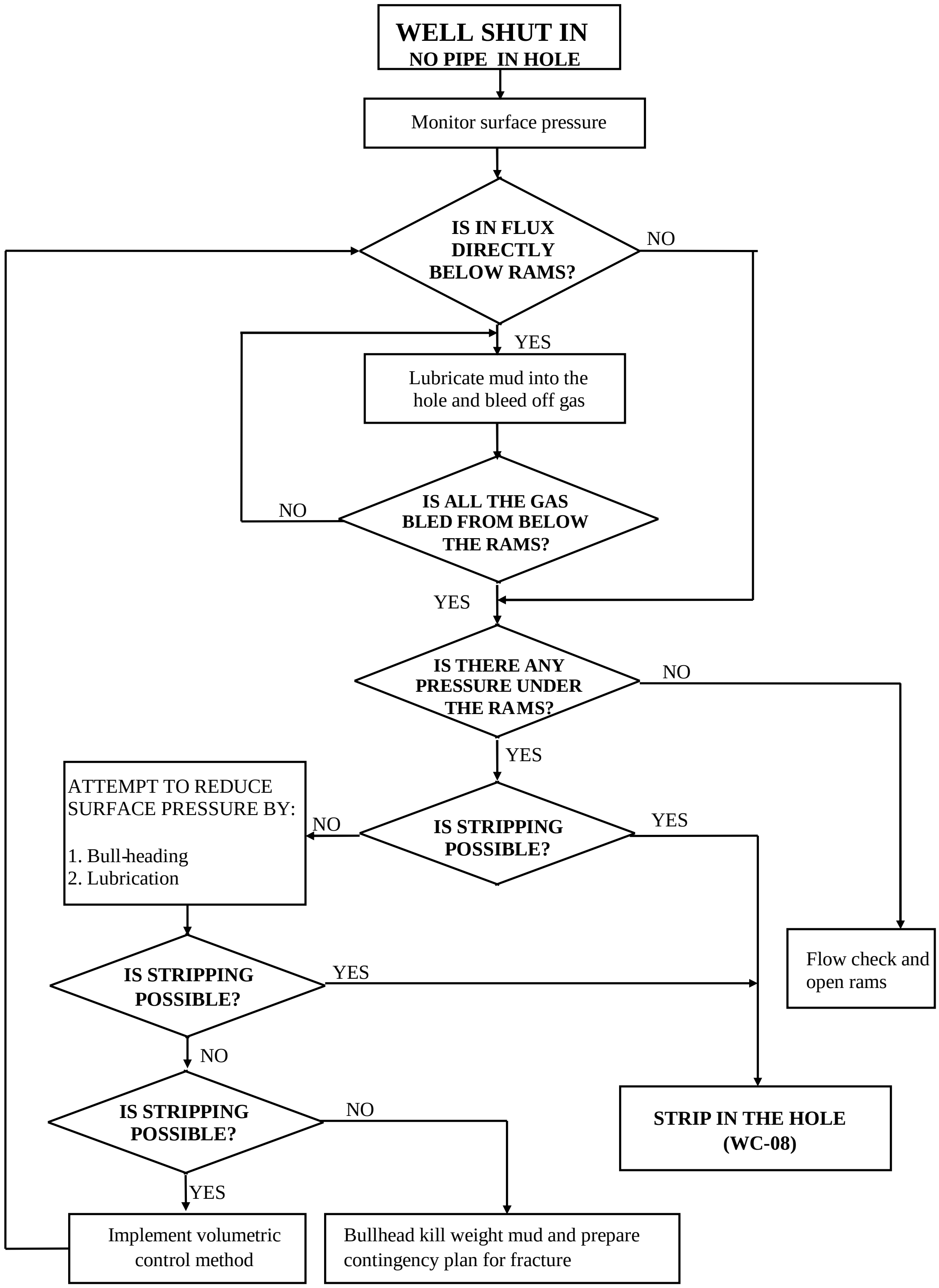
Flowchart: WC-07 No Pipe In Hole



5.5 STRIPPING

The easiest method of stripping on a semi submersible installation, both from a procedural standpoint and in terms of wear on equipment, is annular preventer stripping, using the upper annular preventer.

Annular preventer stripping will be used to get the drillstring to bottom in the event that a kick has been taken with the string out of the hole or off bottom.

A detailed, Rig specific, stripping plan will be developed from the following outline:-

1. Well has been shut in, with non-return valve (Gray Valve/HDIS Dart) installed as part of shut in procedure.

2. Monitor surface pressures to decide if migration is occurring. Decide if string weight is sufficient to strip in. If string weight will not overcome well bore pressure, the annular pressure must be reduced by bullheading or lubricating heavy mud into the wellbore.

3. Calculate pipe displacement and draw up Stripping Worksheet, (include predictions for pressure changes when string enters influx).

4. Decide on an overbalance margin to be maintained during stripping operations if influx migrating allows this overbalance to develop. If no migration is occurring, develop overbalance, by restricting mud bled from the hole, once stripping commences.

5. Reduce annular preventer closing pressure and lower string through closed annular preventer, reduce running speed as tooljoint passes through annular preventer.

6. Station a person close to the BOP control panel, with instructions to shut the well in with a set of pipe rams as a precaution against failure of the annular preventer sealing element or hydraulic closing system.

7. Follow stripping worksheet pressure schedule, (guidance available from Flowchart WC - 08) and estimated pressure changes when string enters influx.

8. Keep trip tank lined up on riser to check on annular preventer element's sealing.

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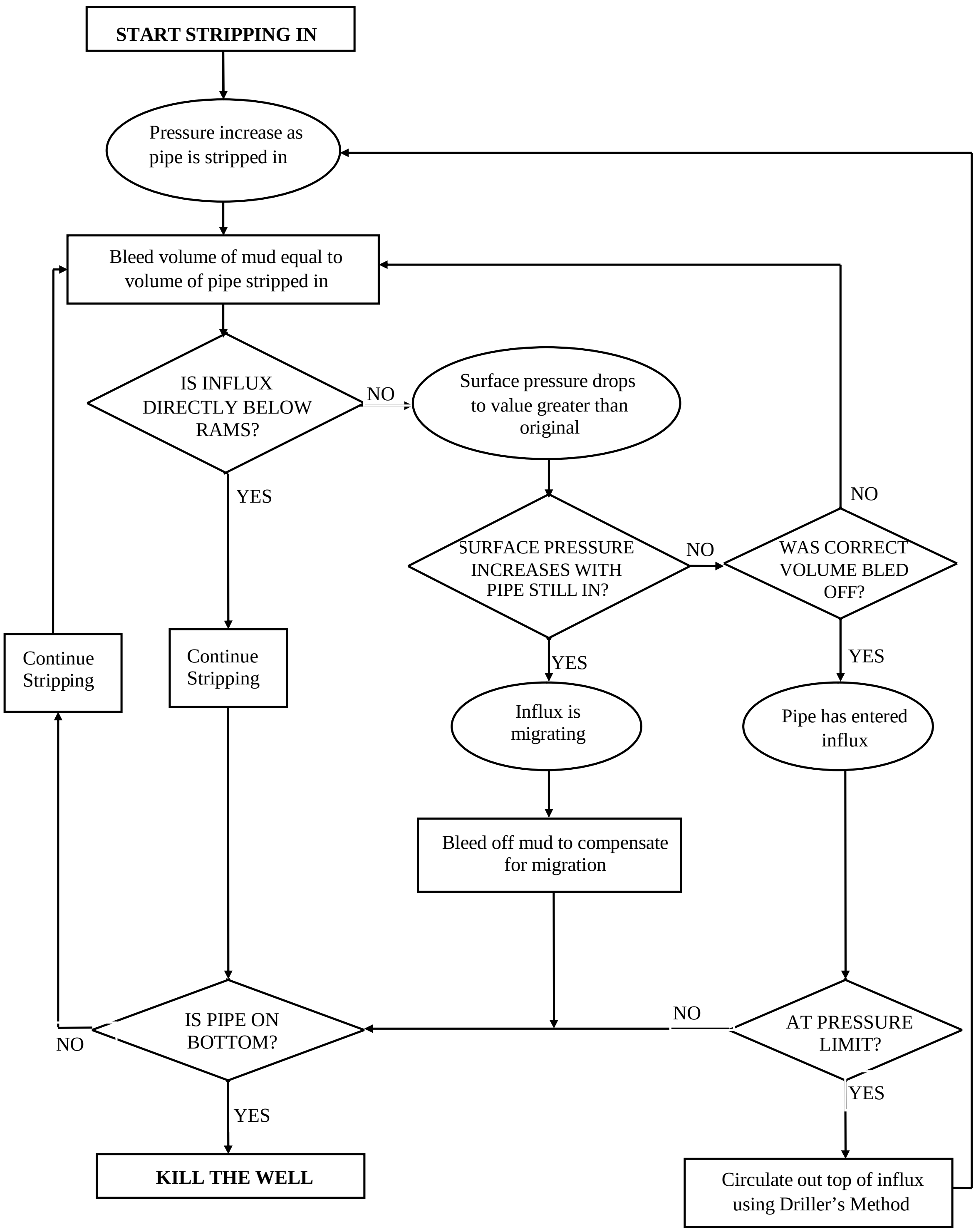
Flowchart: WC-08 Stripping



5.6 WHILE RUNNING CASING (OR LINER)

Before pulling out of the hole, prior to running casing, every effort will be made to ensure that the drilling fluid is conditioned and the well is under control in order to minimise the risk of well control problems while running casing.

Possible causes of well control problems while running casing include:-

- A kick that was swabbed in on the last trip out of the hole
- Swabbing in a kick on a connection while running the casing or working the casing through tight spots
- Swab/Surge pressures generated by vessel movement
- Surge pressures while running casing too fast leading to losses and inducing an influx
- When casing is run to cure a well control problem, such as after controlling an underground blow-out

Particular attention should be given to fluid monitoring when running casing to allow the above conditions to be detected as early as possible.

It is impractical to detail the procedure required in the event that a kick is taken while running casing or a liner. The immediate priority however, will be to close in the well, but the most suitable control technique can only be determined bearing in mind the particular conditions. As it is always possible that there may be a requirement to shut an annular on casing, it is good practice (and therefore recommended), that the annular closing pressure be adjusted before starting to run casing to the pressure recommended for casing size, in the Manufacturers Operating Instructions.

Some of the available options can be summarised as follows:-

- Cross over to drillpipe (unless current string weight is too great) and strip to bottom to kill the well
- Cross over to drillpipe, strip in until drillpipe is through the BOP and kill the well at current shoe depth
- Kill the well with the casing through the BOP
- Drop the casing
- Shear the casing

The major factors that will determine the course of action will include the following:-

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- The possibility of collapsing the casing
- The possibility of the casing being forced out of the hole by the well pressure
- The feasibility of circulating out the kick by conventional means. (The small annular clearance may prevent circulation or cause excessive pressures)
- The feasibility of killing the well by bullheading or volumetric methods.

5.7 UNDERGROUND BLOWOUT

5.7.1 Flow to a Zone Above a High Pressure Zone

The majority of underground blowouts have been as a result of a fracture to a weak zone up the hole as a high-pressure zone is penetrated.

If an underground blowout is suspected, standard well control techniques should not be attempted to regain control of the well. If the annulus is opened, formation fluids will flow up the well bore to surface, thereby increasing surface pressures and possibly causing further fracture.

A simple test will determine whether the well is a closed system. A small displacement pump should be lined up to the drillpipe and a small amount of fluid pumped. If drillpipe and casing pressures increase, there is no indication of formation fracture. If the drillpipe pressure does not increase, or if an increase is not evident in the casing pressure, then there is a possibility that the formation is fractured.

In order to halt an underground flow it will be necessary to pump fluid at a high rate down the drillpipe and up the annulus. The fluid will eventually have to be at kill weight in order to contain the pressure of the zone that is flowing but it will require as low a viscosity as possible to ensure that it can be pumped at as high a rate as possible without generating excessive circulating pressures.

Generally, the kill mud must flow at least as fast as the underground flow if it is not to be dispersed as it comes out of the bit. The formation pressure of the zone that is kicking can only be estimated because a reliable SIDPP will not be available. The mud weight required to kill the well will depend on the position of the fracture in the wellbore and the average weight of the fluid occupying the annulus between the fracture and surface.

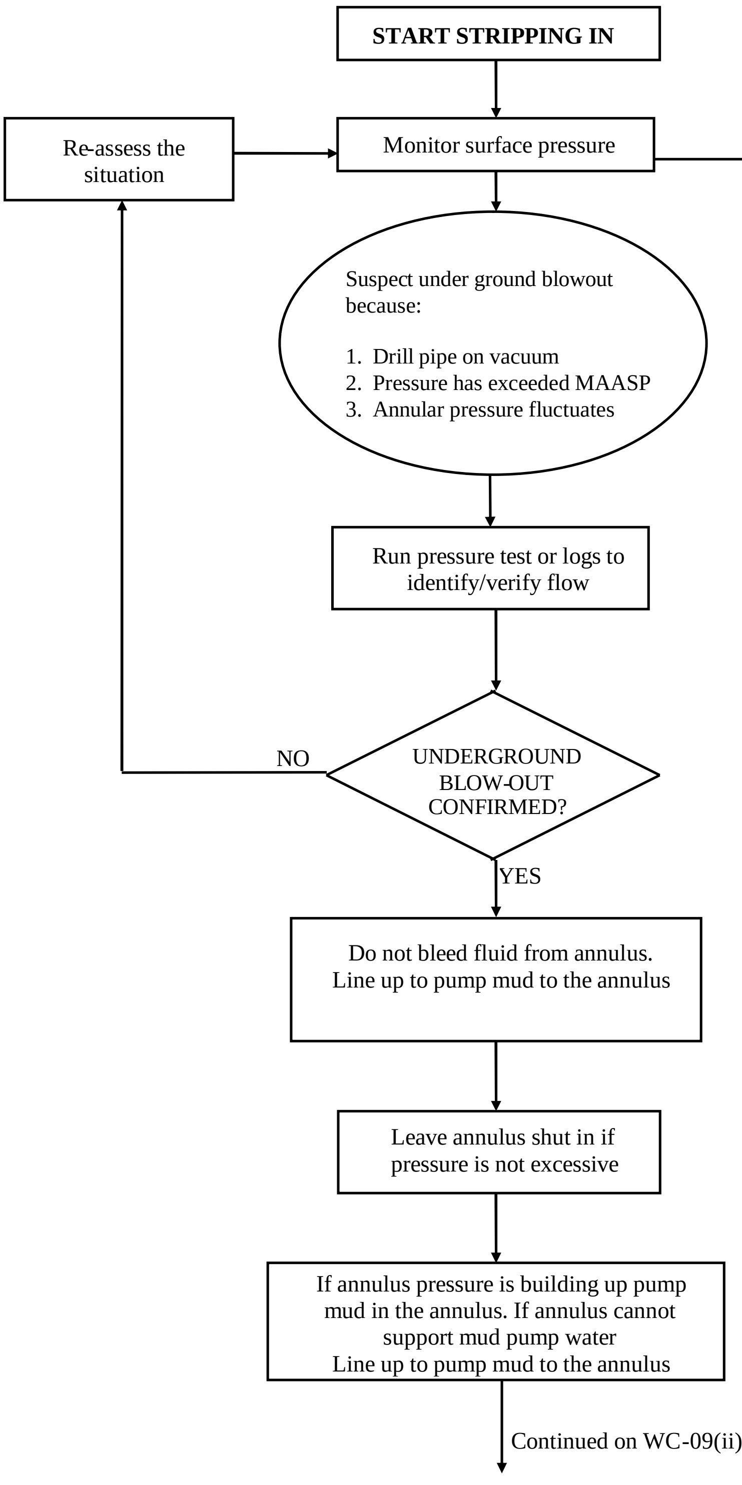
The fracture may only support a column of water, in which case it will be necessary to balance the kick zone pressure with the sum of the hydrostatic pressure of the kill weight mud from the kick zone to the fracture, and the hydrostatic pressure of the water above the fracture.

If the first attempt to control the flow is unsuccessful, the most likely causes will be either that the volume or the velocity of kill mud was insufficient. Subsequent options therefore include increasing the volume of the kill mud pumped and pumping at a greater rate.

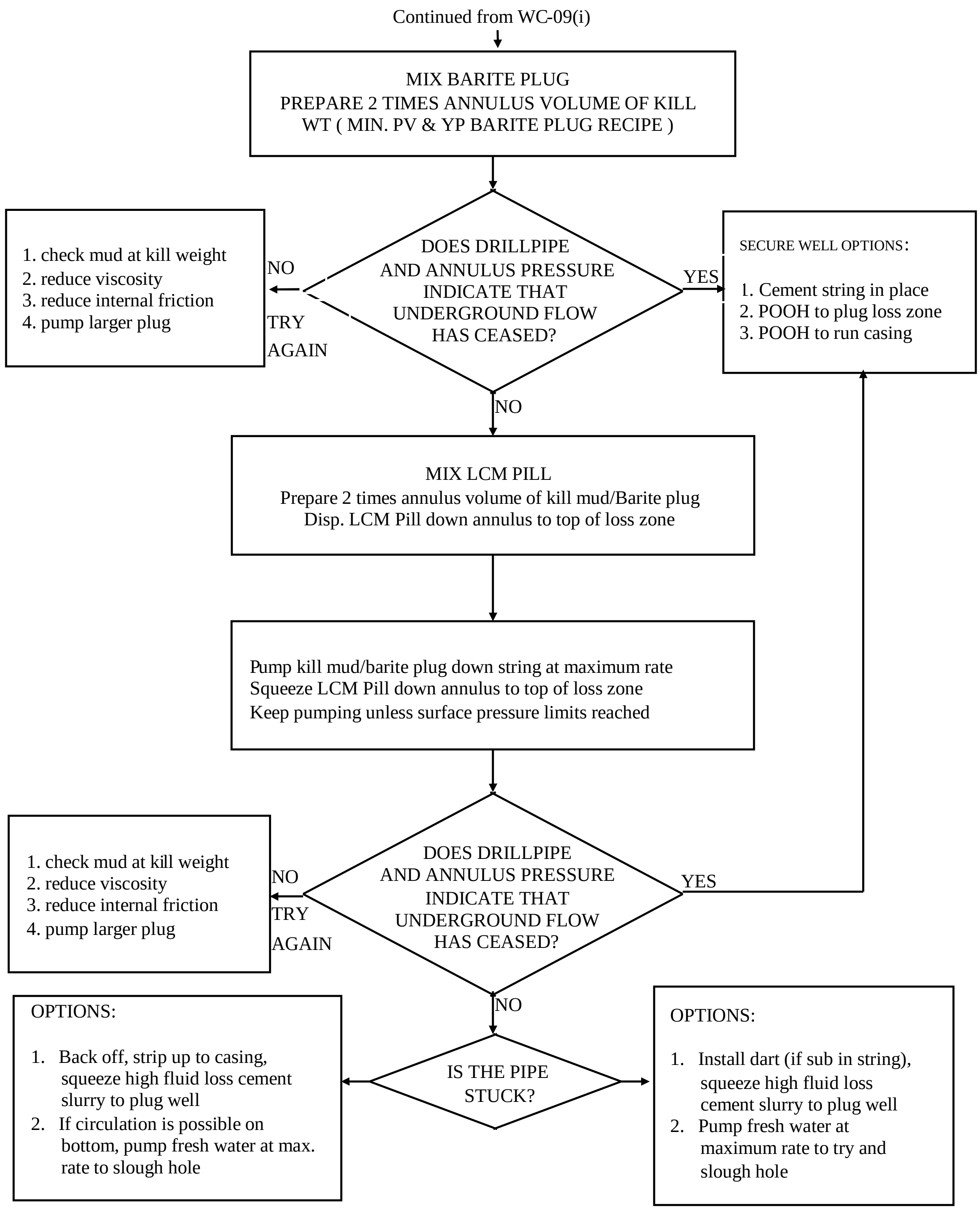
There remains the option of reducing the frictional resistance of the drillstring by such measures as:-

- Removing the nozzles of the bit with a charge run on wireline
- Perforating the BHA close to the bit
- Pumping a lighter, less viscous mud ahead of the kill weight mud in order to reduce the velocity of the inflow

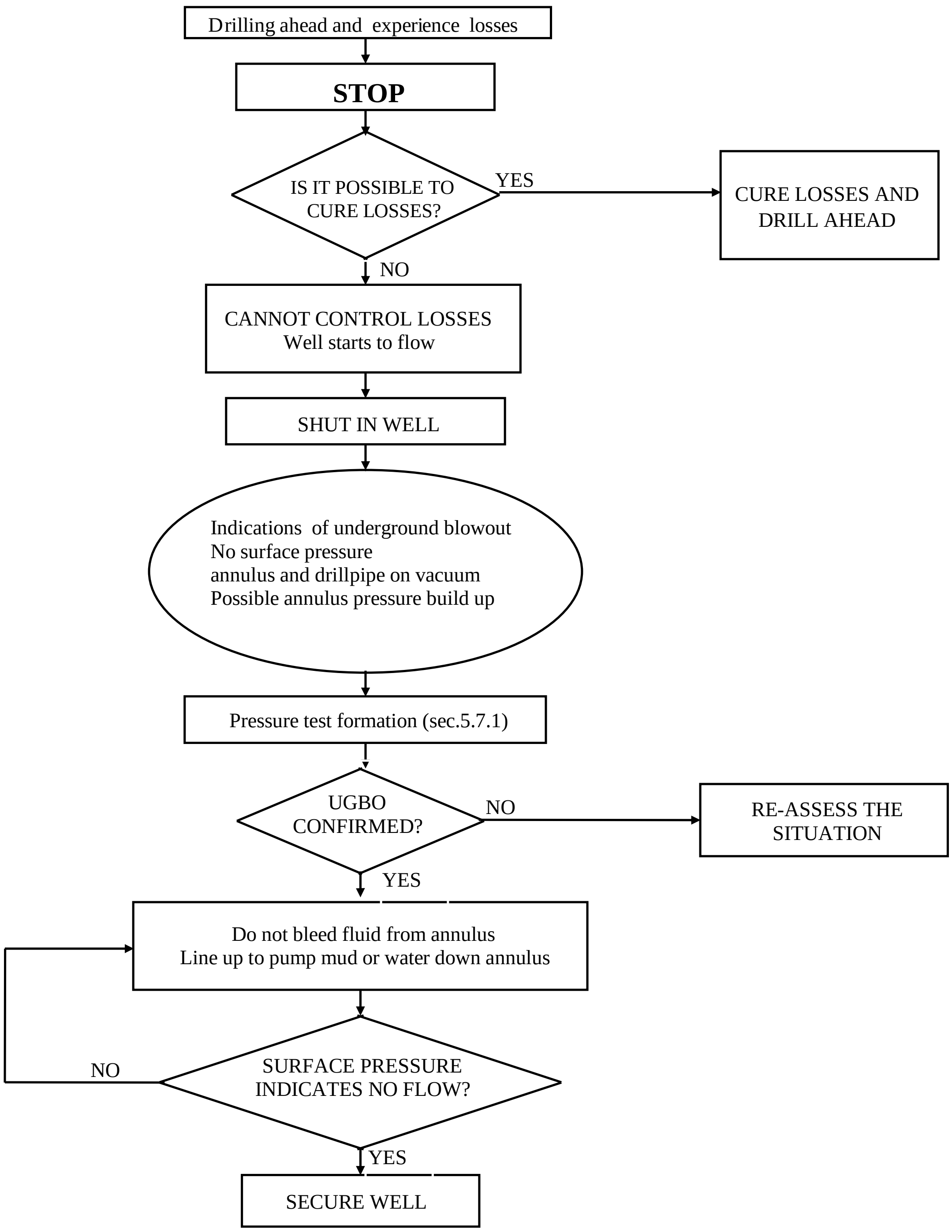
Flowchart: WC-09(i) Flow to a Zone Above a High Pressure Zone



Flowchart: WC-09(ii) Flow to a Zone Above a High Pressure Zone



Flowchart: WC-10 Flow to a Zone Below a High Pressure Zone



5.7.1 Flow to a Zone Above a High Pressure Zone *(Continued)*

If these measures do not bring the well under control, there remains the option to mix an LCM pill or barite plug (See Section 6.8), and displace it down the annulus and into the fracture as the kill weight mud is pumped down the drillpipe. The pump rates on the drillpipe and the annulus should be such as to ensure that the LCM pill or barite plug is completely displaced into the fracture over the period of time that will be required to pump the prepared volume of kill weight mud.

Past experience has shown that in many cases, having halted the underground flow, a further flow has been initiated by attempts to pull off bottom. If the decision is made to pull off bottom having halted an underground flow, extreme care should be taken.

5.7.2 Flow to a Zone Below a High Pressure Zone

The most likely cause of an underground blowout that flows down the wellbore from a high-pressure zone is that a naturally fractured or cavernous formation is drilled into. The resultant losses reduce the hydrostatic head of the drilling fluid to such an extent that a permeable zone higher up the wellbore begins to flow.

When the well is shut in, it is unlikely that any pressure will be recorded on either the drillpipe or the casing gauges. However, the casing pressure may increase if gas migrates up the casing/drillpipe annulus; pumping mud down the annulus prevents this rise in pressure.

Having established that the flow is downwards to a loss zone, there is a suggested option that should be considered for halting the flow:-

- Control losses with LCM until all of the loss zone is exposed to the wellbore and squeeze cement in to the zone.

6.0 WELL KILL TECHNIQUES

6.1 RESPONSIBILITIES

6.1.1 Offshore Installation Manager (OIM)

The OIM has the responsibility of ensuring that those he appoints to positions with a well control function are competent to fulfil that function, have received the training required by Government regulation and the Company's training matrix, and have been made aware, through instruction and exercise, of the actions required of them.

During well killing, as at all times, the OIM has the responsibility of ensuring that operations are planned and executed with the highest regard for the safety of personnel, the installation and the environment.

6.1.2 Rig Superintendent/Toolpusher

It is the Rig Superintendent/Toolpusher's duty to keep the OIM informed and advised of matters, such as well control problems, which might affect the safety of personnel or the installation.

It is the Rig Superintendent/Toolpusher's responsibility to ensure that he and those whom he supervises, i.e., Drillers and Drill Crews, are competent to deal with well control problems when they occur and have received the required training and exercise to become confident in recognising and dealing with well control problems.

It is the Rig Superintendent/Toolpusher's responsibility, in consultation with the Operator's Representative, to advise the OIM on the well kill method that should be used. Unless there is no possible way it can be accomplished, a "constant bottom hole pressure" method of well killing will be used.

Once the well kill planning is complete it will be the Rig Superintendent/Toolpusher's responsibility to execute the plan with all due regard to safety of personnel, the installation and the environment.

6.1.3 Bargemaster

The Bargemaster has responsibility for the marine operations, logistics and weather forecasting. These will be of vital importance during well kill operations when complications, due to bad weather or lack of materials, are to be avoided if at all possible.

The Bargemaster will be involved in all phases of well control planning and decision making.

6.1.4 Driller and Drill crew

The Driller is responsible for recognising well control problems and taking immediate, safe action to contain, and thus minimise, the ingress of any formation fluid into a well bore.

It is the Driller's responsibility to ensure that he and his crew are familiar with the Rig's well control plan and understand the actions that will be required of them.

It is the Driller's responsibility to check that safety valves and all equipment required for monitoring and recording drilling fluid volumes, flowrates, pump speed and casing, and drill pipe pressures is in a serviceable condition and ready for immediate use.

6.1.5 Operator's Representative

The Operator's Representative is responsible to the OIM for providing specialist well control advice with, if available, detailed knowledge of the specific area of operation.

Prior to spudding in, it is the Operator's Representative's responsibility to cooperate with the Rig Superintendent/Toolpusher and the OIM in developing a well control plan. If a well control problem does arise it will be the Operator's Representative's responsibility to cooperate with the OIM and Rig Superintendent/Toolpusher in deciding on the specific well control methods to be used to overcome the problem.

6.1.6 Third Party Employees

Those Third Party Employees with well control functions may, if required, be called upon to assist in the development, or implementation, of the well control plan.

6.2 GENERAL

6.2.1 Constant Bottomhole Pressure

In the Company's well control operations, the goal is to maintain a "constant bottomhole pressure", slightly in excess of formation pressure while circulating the kick out at constant pump rate, namely, the kill rate.

6.2.2 Calculations

Well control calculations and the preparation of kill sheets, step down charts, graphs and pressure schedules will not be discussed at any length in this manual. It is anticipated that users of this manual will have a minimum well control qualification to IWCF or WellCap and be competent to make the necessary calculations.

6.3 THE WAIT AND WEIGHT METHOD

6.3.1 Description

The "wait and weight" method is so named because the crew first shuts the well in and waits for kill-weight mud to be mixed. Then new, weighted-up mud is pumped into the hole while old mud and kick fluids are removed through the choke. Pumping in new mud while removing old mud and kick fluids results in lower surface or casing pressure than first circulating the kick out with old mud, and then circulating in new mud. Surface pressure is lower with one circulation because when new mud has filled the drillstring and begins to flow into the annulus, it adds its higher hydrostatic pressure to the back pressure held on the well by the choke. Since the heavy mud adds to bottomhole pressure, the choke must be opened more to maintain the bottomhole pressure constant. The added hydrostatic pressure results in a lower casing pressure required to control the expansion of formation gas in the annulus. Lower casing pressure reduces the chances of formation breakdown at the casing shoe.

The Company's procedure is to use the "wait and weight" method when the kick requires kill mud.

Two important characteristics of the "wait and weight" method should be noted. One is that circulating pressure decreases as new kill-weight mud is circulated down the drillstring. The pump rate must be kept constant. The other is that surface casing pressure cannot be held constant to keep bottomhole pressure constant as new mud fills the drillstring; SICP must be allowed to increase. To understand why circulating pressure/SIDPP decreases as new mud is pumped down the drillstring, it must be kept in mind that:-

- Circulating pressure shows pump pressure when the well is being circulated
- SIDPP also indicates the amount that formation pressure exceeds the hydrostatic pressure of the old mud in the drillstring

Thus, after the new mud weight is calculated from SIDPP and new mud is circulated down the drillpipe, the new mud weight offsets the pressure exerted by the formation on the mud in the pipe and drillpipe pressure decreases to the final circulating pressure (FCP).

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6.3.2 Pump Start Up

Pump start-up procedures can be critical due to choke line friction (CLF), which places pressure on the well that is not shown on the casing pressure gauge. This pressure can be substantial and cannot be neglected, particularly in deeper waters. Procedures to measure CLF are mentioned in Section 1.4.4

6.3.3 Procedure

Company procedure for the "wait and weight" method is:-

1. When the kick occurs, shut the well in and record pressures.

2. Fill out the worksheet and increase the mud weight.

3. When the new mud is ready, open the choke and slowly bring the pump up to kill rate. (With subsea BOP's, let the casing pressure drop by the amount of the choke-line friction pressure.) When the pump is up to the kill rate, observe the drillpipe gauge and hold initial circulating pressure constant by adjusting the choke to the calculated ICP.

4. While keeping the pump rate constant, continue pumping new mud down the pipe. Circulating pressure will decrease as new mud slugs the pipe. The value for circulating pressure can be checked on the kill-sheet graph or step-down chart, and the choke opened or closed to bring circulating pressure to the correct value.

5. When the new-weight mud arrives at the bit, maintain FCP and keep the pump strokes constant until new mud reaches the surface.

6. Stop the pump, close the well in, and check for pressure.

6.4 THE DRILLER'S METHOD

6.4.1 Description

The Driller's method is the most basic of all methods and can be employed in a number of well control situations. The Driller's method has some limitations. For example, casing pressure rises to a maximum value with this method. Since the well is circulated with original weight mud, all of the additional pressure needed to prevent further intrusions of kick fluids into the well must be maintained by holding back-pressure with the choke. No heavier kill-weight mud is used at this stage of the "Driller's method. If gas is in the kick fluid, it will expand as it is circulated up the hole because of reduced pressure near the surface. Also, the choke size must be reduced when gas reaches the choke to maintain bottomhole pressure. This is a critical point in controlling the drillpipe pressure; if it drops too low, more formation fluid will enter the wellbore and if it becomes too high, the formation will fracture and lost circulation could lead to broaching or an underground blowout.

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The Driller's method requires a relatively long time to kill the well; at least two circulations - one to circulate the influx out, and one to circulate kill mud into and up the hole. Since pressure on the BOP stack is maintained during the two circulations, the possibility of other troubles occurring increases. Moreover, the Driller's method has limited use on Rigs with subsea BOP stacks because pressure losses through the choke line cause back-pressure which must be added to the already high casing pressure (if improperly managed) that could occur with the method. Where a subsea stack is in use, the chance of formation breakdown and lost returns can be high. In spite of its limitations, however, the Driller's method is acceptable when the danger of lost returns is minimal. Also, circulation can begin immediately, thus lessening the chance of the drillstring getting stuck.

To sum up, the Driller's method is not recommended when:-

- Lost returns are likely
- Only surface casing is set
- Long strings of casing have badly worn spots

In short, the Driller's method is best used when little or no danger of lost circulation exists, when Rig equipment or material shortages do not permit using the "wait and weight" method or when a kick has been swabbed in and there is no requirement to increase mud weight.

6.4.2 Pump Start Up

Pump start-up procedures can be critical due to choke line friction (CLF) which places pressure on the well that is not shown on the casing pressure gauge. This pressure can be substantial and cannot be neglected, particularly in deeper waters. Procedures to measure CLF are mentioned in Section 1.4.4

6.4.3 Procedure

Company's procedure for the Driller's method of well control is:-

1. When the kick occurs, shut-in the well in and record pressures.

2. Complete kill sheet.

3. To start circulating - open the choke. Allow the casing pressure to reduce by an amount of pressure equal to choke line friction.

4. When the pump is at kill-rate speed, observe the drillpipe gauge and hold initial circulating pressure constant by adjusting the choke. Maintain a constant pump rate. Do not allow the pump to change speed.

5. Circulate the influx out, holding ICP constant at the original value until the kick is circulated out of the hole. When all of the influx has been pumped out, the well is again shut in. Both SIDPP and SICP will reach the original SIDPP noted when the

kick occurred if the kick is caused by abnormal pressure (or read 0 for a "swabbed in" or "improper hole fill" caused kick).

6. Stop the pump, close the choke, and mix kill-weight mud.

7. When kill weight mud is ready, start circulating - See Step 3.

8. Hold casing pressure constant until kill mud reaches bit (final circulating pressure is reached).

9. Choke operator monitors standpipe pressure and manipulates choke to maintain final circulating pressure.

6.5 VOLUMETRIC METHOD

6.5.1 Description

The volumetric method is used for controlling bottomhole pressure when no drillpipe communication exists or when the well cannot be circulated. It can also be used when the well is closed in and the crew is waiting on orders or equipment. Further, it can be used when stripping in or out of the hole.

The technique is not a well-killing method in the sense of being a method of circulating, since it simply coordinates the increase or decrease of annular pressure with the amount of mud displaced from the hole. The basis of the volumetric method is that each barrel of mud contributes a certain hydrostatic pressure to the bottom of the hole, which may be measured as pounds per square inch, per barrel (psi/bbl). In other words, if 1 bbl of fluid is bled off, then bottomhole pressure is reduced by the amount of pressure exerted by that 1 bbl. If 1bbl of fluid is pumped in, then the pressure exerted by that 1bbl increases bottomhole pressure. To obtain a value for psi/bbl, the mud gradient in psi/ft is divided by the annular capacity in bbl/ft, or the hole capacity in bbl/ft if no pipe is in the hole. The formula is:-

$$MW \times .052 \div \text{Annular Capacity (at top of well)} = \text{psi/bbl.}$$

The value for psi/bbl must be coordinated with pit volume or fill-up tank volume so that the number of barrels may be read directly.

To use the method, the well is closed in, pressure stabilised and the SICP is recorded. If the SICP does not rise, the bottomhole pressure remains constant. If SICP rises, mud can be bled from the well according to the calculated psi/bbl value in order to maintain constant bottomhole pressure. Since bottomhole pressure is the sum of casing pressure and pressure exerted by the mud column, the volumetric method of bleeding off excess casing pressure by adding mud hydrostatic pressure works.

In summary, the volumetric method may be used when:-

1. No pipe is in the hole.
2. The bit is a long distance off bottom.
3. The bit or the drillstring is plugged.
4. Stripping in or out of the hole.
5. Not enough weighting material is available on the location
6. Awaiting the arrival of perforating equipment.

6.5.2 Procedure

When a well is shut-in under pressure, a step-by-step procedure for the volumetric method is:-

1. Record SICP.
2. Line up the choke line to a manual choke so that fluid can be discharged into an accurately graduated tank, such as the trip tank or stripping tank.
3. Calculate the psi/bbl of fluid bled from or added to the well.
4. Monitor SICP and allow it to increase 100psi; this increase occurs as the gas bubble migrates up the hole. This will be used as a safety margin.
5. Allow SICP to rise by the amount equal to the pressure reductions to be made in steps on the well.
6. Bleed metered volume of mud from the well while holding the SICP constant.
7. Repeat as necessary.

6.6 BULLHEADING

Bullheading into a well is forcing gas back into a formation by pumping into the annulus from the surface. The well remains closed in so that mud and kick fluids are displaced into the weakest exposed formation. Bullheading is not a routine procedure, but it can mean the difference between a lost well and one that is under control and returned to normal operations.

Bullheading may be used when:-

- Anticipated surface pressures are expected to exceed the pressure limitations of the surface equipment.

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- When kick fluids, such as H_2S, are hazardous if circulated to the surface.
- When the drillpipe is plugged or parted so that kill mud cannot be circulated to bottom.
- When a weak zone below the kick takes mud too fast for the well to be killed.

When bullheading with water based mud, pump rate must be fast enough to exceed the rate at which the gas migrates up the hole. One indication of too low a pumping rate is an increase, rather than a decrease, in pump pressure. Ideally, bullheading will fracture a formation and continued pump pressure will force gas back into the formation. Anytime high pressure is applied at the surface; a formation breakdown is possible at the casing shoe rather than at a point lower in the hole. Should fracture at the shoe occur, an underground blowout may develop and broaching around the casing is a possibility. Therefore, bullheading is not without risk and caution should be exercised whenever the principle is employed.

6.7 BARITE/CEMENT PLUGS

A barite plug is a slurry of barite and fresh water mixed to a density of about 21 ppg. A phosphate thinner, such as sodium acid pyrophosphate (SAPP), is usually added to the fresh water at a concentration of about 0.7lb/bbl of water. After the acidic phosphate thinner is added, the pH of the fresh water should be increased to about 9.0 by the addition of caustic. Approximately 0.25lb of caustic per barrel of water should be required. The phosphate thinner promotes rapid settling of the barite as soon as slurry agitation is stopped. When settled, barite forms an almost impermeable seal in the wellbore. Since a barite plug requires vigorous agitation (to prevent settling of the barite), the mixing and pumping equipment normally used for cement slurries should be used to place the plug. Often, the first attempt to seal the well is made using a slug volume designed for a plug of settled barite, a few hundred feet in length.

The smaller barite plugs are often placed in a manner similar to a balanced cement plug. The slurry is under-displaced to prevent contamination of the annular plug, and the pipe is then pulled quickly above the plug. The heavy plug should fall free as the pipe is pulled. The well is then circulated above the plug for several hours.

When conditions are more severe, a small barite plug may not result in a successful seal. Large barite plugs involving the use of several thousand sacks of barite are sometimes used when very high sub-surface well flow rates are involved. When using a large plug, no attempt is made to withdraw the drillpipe, and the drillpipe is allowed to become stuck. The drillpipe is over-displaced to prevent the barite from settling in the drillpipe so that if the plug fails, another attempt can be made.

If the barite plug is successful, a small cement plug designed to seal off the inside of the lower portion of the drillstring follows it. The drillstring is backed off above the zone where it is stuck, and the well is circulated for several hours.

The use of barite slurries for sealing high-pressure zones in well control operations has developed over the past decades as an alternative to the use of cement slurries. Cement slurries still have a place in well control, but it is often the case that an effective seal can not be accomplished using cement when the sub-surface flow is primarily gas. Gas tends to channel

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through the cement plug before it sets. Generally, better results are obtained with the rapid-settling barite slurries.

6.8 COMPLICATIONS DURING WELL CONTROL OPERATIONS

6.8.1 Introduction

Current well control teaching, deals primarily with relatively uncomplicated situations in which kicks are taken during drilling with the drillstring at or near bottom with no additional problems or complications being encountered during the well control operation. Unfortunately, when some kicks are being handled, complications develop which may force departure from standard and practiced well control procedures. While it is not possible to anticipate all problems that can occur, a Well Control Procedures Manual would not be complete without covering some of the more common complications that have occurred in the past.

It should be noted that each situation will have its own circumstances and the emphasis of planning and decision making must be on considering ALL possibilities, and having every effort directed towards "NOT MAKING A BAD SITUATION WORSE".

6.8.2 Gas Migration

After a kick is detected and the well is shut in, the well pressures initially increase in response to formation flow. As the fluids trapped in the well are compressed and the well pressures rise, this flow gradually decreases and finally stops.

In some cases, problems may develop which prevent the initiation of kick circulation for long periods of time. In other cases, problems may develop during kick circulation, which require that the well be shut in again with kick fluids still in the well. If the kick fluid is gas and the well remains shut-in for a long period of time, the gaseous formation fluid trapped in the annulus may migrate a significant distance towards the surface.

Gas rising in a shut-in well will cause a gradual increase in pressure at all points in the well. This pressure increase occurs because the gas cannot expand if the well remains closed. If the gas is not allowed to expand as it travels up the hole, it retains the same pressure and exerts this pressure in all directions. This means increases in pressure at the surface, at bottom, and at all depths in the hole, which will eventually cause formation fracture or equipment failure. In order to avoid this unacceptably large increase in well pressure, the gas should be allowed to expand under controlled conditions to keep the bottomhole pressure constant at a value slightly above the formation pressure.

Controlled expansion gas rising in a shut-in well is best accomplished using the hand-adjustable choke. After the SIDPP has stabilised, note the drillpipe and casing pressures. Allow the SIDPP to rise about 100psi to provide a safety margin for choke operations. Then, wait and permit the SIDPP to further elevate by the amount of pressure you wish to reduce on the SIDPP (50psi is usually a good figure).

Pressure on the SIDPP now will have:-

1. Stabilised

2. Risen to provide a safety margin of ± 100psi

3. Further risen by the amount of pressure that the SIDPP is to be reduced as fluid is removed through the choke

Now, the Choke Operator cracks the choke open and bleeds off a defined quantity of drilling fluid (¼ or ½bbl). He closes the choke and waits for the choke lag time to pass. He repeats the procedure as necessary to achieve the selected "SIDPP + safety margin value".

Well pressure will be maintained above formation pressure and further flow of formation fluid into the wellbore will be prevented. This method of bleeding off a specified small volume of fluid and then waiting for pressures to stabilise should always be used because of the lag time involved between choke manipulation and the corresponding response in drillpipe pressure.

After all of the gas has migrated to the top of the well, casing pressure will become and remain static. The well should then remain shut in until well circulation is possible. Although gas is at the surface, well circulation can be initiated in the conventional manner, i.e., by holding the casing pressure constant while bringing the pump up to speed. Very little initial choke adjustment will be required while starting the pump because of the large volume of compressible, low-viscosity gas at the surface.

Just before the gas reaches the surface, the casing pressure will tend to increase rapidly, requiring more frequent intervals of bleeding mud through the choke. It may be difficult to initiate well circulation properly during this period. Under these conditions, it is recommended that all of the gas is allowed to migrate and pressures allowed to stabilise before initiating circulation.

This procedure will maintain the bottomhole pressure slightly above formation pressure and prevent further influx of formation fluid into the well. Although the casing pressure will tend to increase over the initial shut-in casing pressure, much lower casing pressures will result than if no mud were released. The chance of formation breakdown or equipment failure will be greatly reduced.

6.8.3 <u>Surface Equipment Problems</u>

Perhaps the most frequent complications experienced during well control operations are related to problems with the surface well control equipment. The more common surface equipment problems include:-

1. Plugged choke.
2. Erosion of choke or choke manifold.
3. Pump problems.

4. Leak in sealing elements of the BOP stack.

Usually, these problems are not serious if they are diagnosed quickly and corrected. Surface equipment problems not evident from leaks or power failures are generally detected by a departure of the drillpipe pressure and/or casing pressure from normal behavior. As soon as a problem with the surface equipment is suspected, the pump should be stopped immediately and the well closed in. The pump operator should always remain at his station and be ready to stop the pump immediately if so instructed by the choke operator.

6.8.3.1 **Plugged Choke**

Formation fragments carried by the drilling fluid will sometimes lodge in the choke, creating a plug. This situation will be apparent from a rapid rise in both the drillpipe pressure and casing pressure. When this situation exists, it is very important to stop the pump immediately. The choke can be fully opened, for an instant, in an attempt to dislodge the plug (if possible this should be done without allowing drillpipe pressure to fall below schedule).

If this fails, surface flow should be re-routed to another choke. Any trapped pressure should be released by periodically bleeding a small volume of mud until the shut-in drillpipe pressure returns to approximately the proper shut-in value. The well control operations can then be resumed.

6.8.3.2 **Erosion of Choke or Choke Manifold**

Abrasive solids, such as sand carried by the drilling fluid, can cause erosion in the high pressure piping system. A cut-out choke can result in simultaneous decrease in drillpipe pressure and casing pressure that cannot be corrected by choke manipulation.

After stopping the pump and closing the choke, it will probably also be necessary to close a valve in the choke manifold to stop the flow completely. Well control operations can normally be resumed after re-routing the surface flow to another choke.

If fluid erosion results in a leak in the choke manifold system at a location that cannot be conveniently bypassed, the well can remain shut in until the problem can be corrected. However, the shut-in well should be continually monitored for pressure increases due to upward gas migration.

6.8.3.4 **Pump Problems**

In the event of pump failure, the well should be shut in until another pump can be brought on line. Since the slow circulating rate pressure of the second pump may be different, it may be necessary to use a different circulating drillpipe pressure. The new drillpipe pressure can be determined by bringing the pump up to speed while adjusting the choke to hold the casing pressure constant.

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After the new pump is running at the desired kill speed, the new circulating drillpipe pressure should be equal to the observed drillpipe pressure reading at that time. The slow circulating rate pressure for that pump speed is the difference between the observed circulating drillpipe pressure just after pump start-up and the shut-in drillpipe pressure.

If kill mud has not yet reached the bit, a new drillpipe pressure schedule should be drawn up, based on the new value for reduced pump pressure.

In some cases the pump may not fail completely, but may change significantly in displacement efficiency because of a bad piston, valve, or some other problem. This problem can usually be detected by erratic drillpipe pressure behavior or by gradually decaying drillpipe pressure. If the problem goes undetected, the choke operator will tend to compensate by closing the choke in order to increase the drillpipe pressure back to the desired value.

6.8.3.5 **Leak in Sealing Elements of the BOP Stack**

Occasionally, as casing pressures increase during the circulation of the kick, a leak may develop across the annular preventer, at a ram, or at a connection in the BOP stack. After stopping the pump, pressure at the leak can usually be bled off by closing one of the lower rams below the leak. Subsea BOP stacks should, if possible, is monitored during well control operations with subsea TV or ROV equipment.

6.8.4 **Sub-Surface Problems**

In addition to problems with the surface well control equipment, mechanical problems with the sub-surface well circulation can and occasionally do occur during the well control operations. Some of the more common sub-surface well problems discussed in this section include:-

1. Plugged bit.
2. Bit nozzle washout.
3. Hole in the drillstring.
4. Borehole fracture, cement failure, or casing failure.

Sub-surface well problems generally must be detected and diagnosed from the behavior of drillpipe and casing pressure, and from records of pit volume changes. As in the case of surface equipment failures, the first step taken when well problems are detected is to stop the pump immediately and shut-in the well.

6.8.4.1 **Plugged Bit**

Debris that enters the drillstring during a kick or is circulated down the drillstring will result occasionally in a plugged bit. In some cases, only partial plugging results, while, in others, well circulation is completely stopped. Bit

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plugging can be detected at the surface by a sudden increase in the circulation drillpipe pressure without a corresponding increase in casing pressure.

If only partial plugging is present, it may be possible to continue kick circulation at a higher drillpipe pressure or a lower circulation rate. The pump can be brought up to speed while simultaneously holding the casing pressure constant at the shut-in value in order to determine the new reduced circulating pressure. The new pump pressure can be determined as the difference between the observed drillpipe pressure just after start-up and the shut-in drillpipe pressure.

If heavy mud has not yet reached the bit, a new drillpipe pressure schedule should be computed based on the new value for reduced pump pressure. The choke operator should also remain alert for a sudden decrease in drillpipe pressure, which indicates that the plug may be breaking free. The choke operator can verify the current pump pressure at any time by stopping the well control operation and then restarting the pump at constant casing pressure.

If a partially plugged bit or drillstring is not correctly diagnosed, the choke operator will tend to open the choke in order to get the drillpipe pressure back on schedule. This will result in a decrease in the casing pressure and bottomhole pressure, allowing the influx of formation fluid into the well to resume. Should this condition continue unnoticed for a long period of time, a very large influx may be taken.

A completely plugged drillstring may have to be perforated so that well circulation can be resumed. The hole should be placed as close as possible to the bottom of the drillstring to insure that most of the kick fluids are above the hole. Otherwise, it may not be possible to maintain the bottomhole pressure constant using conventional well control procedures. The new reduced circulating pressure which results after perforating the drillstring should be established as discussed previously by maintaining a constant casing pressure during pump start-up.

6.8.4.2 **Bit Nozzle Washout**

A bit nozzle washout results in a sudden decrease in drillpipe pressure without a corresponding decrease in casing pressure. As in the case of a partially plugged bit, the well control operation can be continued after the new value for the reduced circulating pressure is established.

6.8.4.3 **Hole in the Drillstring**

In a few instances, well control operations have been complicated by the development of a washed-out hole in the drillstring. This can be detected at the surface by a rapid decrease in drillpipe pressure without a corresponding decrease in casing pressure. The location of the hole with respect to the kick fluids can sometimes be estimated from the drillpipe pressure after shut-in.

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If the drillpipe pressure is much higher than the expected shut-in drillpipe pressure and does not respond to bleeding a small volume of mud, a hole above the kick zone is indicated.

If no kill mud is in the drillpipe, the drillpipe pressure may be the same as the shut-in casing pressure.

If the hole is below the kick zone, the drillpipe pressure will return to near the expected shut-in value. In this case, it will not be possible to distinguish a hole in the drillpipe from a washed-out bit nozzle. However, both of these situations should be handled in the same manner.

When a hole is above the kick zone, it is no longer possible to maintain the bottomhole pressure constant while circulating the kick in the conventional manner.

If upward gas migration is evident and there is a hole in the drillstring, it is not possible to maintain a constant bottomhole pressure by bleeding mud while observing the drillpipe pressure. The upward gas migration can be handled using the same procedure as when the drillstring is off bottom or completely out of the hole. This procedure is the volumetric method. In some cases, it may be practical to wait until the kick zone migrates up past the hole in the drillpipe.

6.8.4.4 **Borehole Fracture, Cement Failure or Casing Failure**

The selection of proper casing setting depths is often critical to the success of a well. In some cases, when a large kick is taken with a long interval of open borehole just prior to the next scheduled casing setting depth, it may not be possible to circulate the kick to the surface without exceeding the fracture pressure of the weakest exposed formation. Once formation fracture occurs, the resulting loss of annular pressure usually allows additional influx of fluids from the high pressure zones into the wellbore. This can lead to an underground blowout situation in which formation fluids flow uncontrolled from the deeper high pressure zone to the more shallow, fractured formation.

The pressurising of shallow formations can lead to dangerous problems for subsequent wells in the area and should be stopped as soon as possible.

Underground blowout situations can also result from failure of the intermediate casing or a cement failure near the bottom of the casing string.

A failure in the sub-surface wellbore, cement, or casing, which causes an uncontrolled loss of well fluids from the sub-surface annulus, can be detected from an unexpected drop in surface pit volume, casing pressure, and drillpipe pressure. If the fluid level in the annulus begins falling, mud should be pumped

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into the annulus to maintain the well full and keep the surface pressures from later building up due to the loss of mud.

Control or isolation of the zone of lost circulation from the high pressure zone that is kicking is critical. One effective means to accomplish this is through the use of a barite plug to seal the lower portion of the well. For a description of the possible uses of a barite plug, refer to Section 6.8.

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6.8.5 Emergency Disconnect from a Pressured Well

In an emergency, a floating Rig depends on the ability to move off location leaving the well shut-in. Rig specific move off plans, an essential part of the installation's Well Control Plan, will be devised by the OIM with the assistance of the Bargemaster and the Rig Superintendent/Toolpusher. Some examples follow to illustrate possible plans of action prior to moving the Rig off location:-

(i) With a dart sub installed in the BHA

1. With pipe hung off on pipe rams below the shear rams, install and pump down a back-pressure or dart valve until seated in the dart sub. Keep casing pressure constant while circulating.
2. After the dart seats, bleed off drillpipe pressure and observe the drillpipe pressure gauge to determine if the dart is holding pressure. (If dart is not holding see Section 6.8.5(ii)).
3. If the dart is holding pressure, and with the drillstring hung off on the upper rams, close the lower pipe rams.
4. Displace mud in the riser with sea water.
5. Close the fail-safe valves; close the shear/blind ram preventer to shear the pipe.
6. Pull out of the hole with the sheared drillpipe.
7. Disconnect the lower marine riser package; confirm disconnect; slack off the guide-line tensioners.
8. Move the Rig off location.

(ii) With no dart sub or leaking dart.

1. With pipe hung off on pipe rams sufficiently below the shear rams to clear the tool joints, close the shear rams and shear the pipe.
2. Close the choke and kill valves on all outlets below the shear rams.
3. Displace mud in the riser with sea water. Use the choke/kill lines, if available, above the shear rams; or subsea booster line, if available; or pump down the sheared drillpipe (sheared drillpipe may allow little or no circulation).
4. Pull the sheared drillpipe out of the hole.

5. Disconnect the lower marine riser package; confirm disconnect; slack off the guide-line tensioners.

6. Move the Rig off location.

6.9 WELL CONTROL IN HORIZONTAL WELLS

Well control in horizontal wells will have to be addressed on a case by case basis. Obviously, the principals of pressure calculations and the difference between "measured depth" and "true vertical depth" are the same as in any directional well, but the potentially large influx volumes possible in an extended reach horizontal section make the necessity for avoiding an influx particularly keen. Precautionary measures against swabbing such as pumping out of the horizontal section are to be used whenever possible.

Continuing research and inquiry on the subject of well control in horizontal wells will lead to this section of this manual being updated as information becomes available.

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7.0 OIL BASED MUD

7.1 INTRODUCTION

The reaction of formation gas with oil based drilling fluids can be quite different from the reaction with water based drilling fluids. Hydrocarbon gas and base oil have many more chemical similarities than hydrocarbon gas and water. When hydrocarbon gas and base oil come into contact in a drilling fluid, the gas needs little persuasion to join up with the base oil in the drilling fluid. This joining or dissolving of the gas into the oil, is called "going into solution". The result of this solution is much like the solution of carbon dioxide (CO_2, a gas) dissolved into a soft drink (liquid). An understanding of the behavior and consequences of this gas/oil solution during well control situations is necessary when using oil base muds.

A major effect of this joining of gas and base oil under the right conditions is that the gas can be hidden with very little to show that it is there, just like the CO_2 in an unopened soft drink. The right conditions for gas being in solution with base oil are the conditions that usually exist downhole in a well. Depending upon these conditions, when 1 bbl volume of gas plus 1 bbl volume of mud join, the result does not equal 2bbls of a gas/mud mixture. There is a reduction in volume when the gas and base oil in the mud join to form a solution. The amount of volume reduction depends upon the make up of the gas, the make up of the mud, the pressure and temperature under which they come in contact, and how they are mixed. This reduction of volume (when combined with the fact that the gas in solution is not free to expand as it moves up the annulus) makes it very difficult to catch this type of kick during a flow check. It may require 5 to 10 minutes with the pumps off while metering returns to the trip tank to be noticeable.

Another effect is the sudden expansion of the gas as it comes out of solution. The primary cause for this is a reduction of pressure just like opening the soft drink. One (1) bbl of gas from the formation will expand the same amount in its trip from downhole to the surface regardless of whether water based or oil based fluid is used. The difference (due to the solubility of the gas and oil) is where that expansion takes place. Gas that is "free" in a water based fluid will expand proportionally to the reduction in pressure as it moves up the annulus. Any free gas with an oil based fluid would do the same; however, any gas dissolved in the oil will not expand until it is free of the solution, or "bubbles out". The point where the gas comes out of the mixture or "bubble point" also depends upon the make up, pressure and temperature of the mixture. With the right conditions, the gas that was dissolved into the mud downhole may not begin to break free until it reaches the surface and gets a little help such as running over the shale shakers (just as you can free the CO_2 in the soft drink by shaking it). More commonly, the gas will come out of solution and begin expanding within the top several hundred feet of the well. You may not know that the gas is there until it unloads your well or riser. An oil base mud can carry enough drilled gas in solution to have the same effect. A gas kick must be detected early to minimise well control problems.

One more effect of the gas dissolving into the base oil of a drilling fluid is that the altered drilling fluid may have different physical properties after the gas is dissolved in the base oil. A drop in viscosity or gel strength would let the solids settle out of the mud and may cause the pipe to stick. Due to this, it is recommended that the mixture is not allowed to sit any longer

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than necessary for proper control of the well. This is a situation where the "Driller's" method and concurrent method of circulating out a kick are often considered.

7.2 EFFECTS OF SATURATION

The types of fluids, how they are mixed, and the mixture's pressure and temperature at any single point in time will determine how much gas can be dissolved into or absorbed by the liquid at that point in time. When the liquid is holding as much gas as it can under those conditions, it is said to be at the "point of saturation" or "saturated". If the liquid is below the point of saturation, it will absorb any more gas it comes into contact with until it reaches the point of saturation. If the liquid is at the point of saturation, any gas it comes into contact with remains as a "free" gas and will not be absorbed.

For the conditions that concern us, the point where the base oil in the mud is able to absorb the greatest amount of gas is found at the temperatures and pressures downhole at the bit. The point where the mud has the most difficulty holding the gas in solution is at the surface. We will look at three different cases and their effect on gas expansion/surface pressures when formation gas mixes with oil based mud at total depth:-

7.2.1 <u>Case I. Unsaturated Mixture</u>

If conditions are such that a gas kick is taken and shut-in without enough influx to saturate the mud with gas, there will be a loss in volume of the gas influx due to the gas going into solution with the mud. There will be no free gas to migrate and expand such that SICP will remain constant. At this point, the kick will act like a salt water kick. Do not assume that it is. While circulating this kick out, a point will be reached where the mixture is at saturation due to the lower pressure caused by a reduction in hydrostatic head. If circulation is stopped at this point, the kick/mud mixture will remain liquid. If pressure is reduced by bleeding off the choke or resuming circulation, the gas will begin to bubble out of the mud. The more the pressure is reduced, the more free gas will bubble out of the mud. As this mixture is circulated further up the hole, increasing amounts of back pressure on the choke will be required to make up for the loss of hydrostatic head from the ever increasing amounts of expanding gas. If you were to bullhead this kick/mud mixture back down the hole, the increasing pressure would force the free gas back into solution until all free gas is dissolved back into the liquid at the saturation point. The point in the hole where the gas begins to break free will depend upon the type of fluids in the mixture, the sum of the hydrostatic head and choke pressure, the temperature and the original saturation level of the kick/mud mixture. It may start separating right off bottom, which will induce "gas expansion pressures" on the formation. It may take place up in the casing, in the choke line, or even downstream of the choke and could expose the Rig to more gas than it has the capability of handling. The longer that the gas is held in solution, the less time it will have to distribute itself through the mud column and the higher the gas concentrations will be upon reaching the surface. High, sudden, and totally unexpected casing pressures can be obtained with this type of kick.

7.2.2 Case II. Saturated Mixture

If conditions produce a kick/mud mixture at saturation point, conditions will be as described above except that free gas will start coming out of the mixture as soon as circulation is started.

7.2.3 Case III. Over-saturated Mixture

When conditions are right and a larger amount of gas influx is taken than that needed to saturate the mud, gas that did not dissolve into the mud will be present as free gas. This will have the same surface indication as a gas kick with a water based mud. It is not. The kick is larger than the surface readings indicated because a portion of the gas influx is hidden in the mud. The hidden portion will remain hidden until the bubble point of the dissolved gas is reached. Only the free gas will be expanding as it moves up the hole. When this expansion is evident, it is an indication that a very difficult procedure will be necessary to kill the well.

7.3 COMPRESSIBILITY

Oil is slightly more compressible than water. This means that it will change volume more than water with a change in pressure (expanding as pressure is reduced and contracting as pressure is increased). Although this change in volume is very small and will not be noticed during normal circulation, it does have some effect. A small expansion of the oil based mud will show up in the slightly longer time it takes flow to stop after shutting off the pumps when compared to water based mud. The reverse of this is that due to mud contraction, it will take longer for pressures to stabilise. It will also take longer for pressures to stabilise when a kick is taken in a high pressure, low permeability zone where slow pressure rises are mistaken for gas migration. If pressures are not given enough time to stabilise, too low a kill weight mud will be used. The increased compressibility will also require more time for pressure stabilisation after choke adjustments than with a water based mud.

7.4 SUMMARY

Any gas kick may cause problems in well control due to problems with gas expansion. These problems can be magnified by the ability of an oil based mud to hide a gas kick due to gas going into solution at downhole conditions. The worst case situation should be looked at. Assume that it is a gas kick. Can the well and surface equipment handle the possible pressures due to gas expansion? Can the Rig's equipment handle the possible concentrations of gas at the surface, even at the slowest possible circulation rates? Should the kick be bullheaded back into the formation? Should it be plugged off instead of circulated out?

Oil based mud can carry enough drilled gas in solution under conditions to unload the top portion of the hole or marine riser when lower pressure and temperature conditions are reached near the surface. Always keep the diverter packer installed. Be ready to fill the hole from the top to make up for any hydrostatic head lost from the mud being blown out of the hole. When circulating out a kick, be prepared for unexpected gas breaking out at any time, even downstream of the choke.

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The solubility of gas in an oil based mud can hide a gas kick sufficiently to keep it from being noticed during a flow check or when making a connection. More time is required and returns may have to be taken at the trip tank to be noticed. Do not let your guard down during the "normal" long time it may take for a flow check due to expansion of the mud.

A gas/oil solution will not support the solids that the oil alone will. Expect solids to fall out of the mud and possibly stick the pipe and/or pack off the hole. Consider using the "Driller's" method or concurrent circulation method.

As with any gas kick, early detection/shut-in and circulation will minimise problems. Expect more and more sudden gas expansion than with a water based mud due to the increasing amounts of gas in the annulus as it comes out of solution. Be ready to safely vent large amounts of gas at the surface. Exercise due caution throughout the circulation but especially in handling the gas through the surface equipment.

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8.0 JACKUP WELL CONTROL PROCEDURES

8.1 OBJECTIVE

To ensure that the operations covering the well control procedures undertaken on a Jackup after the BOP has been installed are carried out in a safe and efficient manner according to an agreed procedure to minimize risk to personnel, equipment and the environment.

Scope

This procedure applies to well control situations on all SeaDrill Jackups with the BOP installed

Background

Unless otherwise specified, blowout prevention systems shall follow the American Petroleum Institution recommended practices, API RP 53. Blowout and well control practices shall comply with the laws of the jurisdiction within which the facility is located.

The Offshore Installation Manager (OIM) shall ensure that the members of the crew are cognizant of the laws and recommended practices for the locale. The OIM shall verify the minimum training required by law for each SeaDrill assigned to his facility.

General Requirements

1. Prior to spudding a new well, the OIM shall be informed about the history of pressures encountered at the well location. The OIM and his Drillers shall share this information, especially the depths and geological sections that might have abnormal pressures. This information is available in the Operational Plan for the well, which is supplied by the operator. The OIM will meet with the Company Representative to agree on the steps, personnel, and stations involved in handling the killing of a kick or the diverting of a blowout. They will also agree on how to rid the stack of any trapped gas before opening the stack after a well kick.
2. Prior to commencing of the procedure and before each tour in a shallow gas suspected area, hold a toolbox meeting with all personnel involved in the operation. Review relevant Job Safety Analyses (JSAs) and modify procedures if necessary.
3. Obtain relevant information from the Operator and agree to a specific step by step well control procedure. Post the written procedure and a Pre-kick Data Sheet (Kill sheet) at the Driller's console.
4. Slow Circulating Rates (SCR) will be taken and recorded prior to drilling out, at least once each tour while drilling, after changing the BHA, after changing the mud weight, and after every 500 feet drilled.

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5. Flow checks shall be made on drilling breaks, flow rate increases, pit gains, decreases in pump pressure with an increase in pump strokes, and any time the Driller suspects that the well may be flowing.
6. Blowout preventer (BOP) control lines and valves must be clearly identified.
7. All valves, manifold piping, fittings, and connections in the BOP system must be able to withstand any pressure for which BOP is rated
8. The hydraulic lines from the accumulator to the BOP stack shall be inspected frequently to determine if they are in good condition, free of leaks, and remain connected
9. Drilling will not continue if the amount of barite on the rig drops below the number of sacks needed to raise the density of the mud in the system by one pound per gallon, or below the number of sacks agreed upon with the Operator prior to commencing drilling.
10. The BOP and choke and kill manifold shall always be lined up and ready for a well control situation.
11. The choke and kill lines shall be pumped through daily at a minimum.
12. Ensure that choke and kill lines are fully open before opening rams or annular after killing a well
13. The duties for each crewman during a BOP or diverter drill shall be conspicuously posted on the rig floor and in other necessary work areas
14. Pit drills and trip drills must be conducted daily and recorded in IADC report.
15. All pre-recorded information requirements must be available at all times at the Driller's console.

Safety Precautions

♦ Extra care and is required to ensure the safety of new or inexperienced personnel.

♦ Personnel must stay clear of the BOP when under pressure

♦ Rig personnel must stay clear from the rotary table opening while the BOP is functioned

♦ During a well kill, personnel must stand clear of high pressure lines at all times. Extra care must be taken during manual choke operations to minimize exposure to high pressure lines. All non-essential personnel must be excluded from the area.

♦ When opening the BOP stack, gas may be trapped in the stack above the choke lines but below the upper most preventer. If the preventer is opened quickly, gas may rush out causing mud, shale, or sand cuttings to be blown out of the hole. The bushings may be blown out of the rotary table. Gas shall be bled off or flushed from the preventers as per SeaDrill well control procedures.

♦ Safety equipment must be tested and ready for use at all times.

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Well Control While Drilling

The decision tree **"Jackup Well Control Procedures - Drilling – FORM A"** outlines the procedures to be used in the event that a kick is taken while drilling. These procedures are intended to be general in order to cover all Jackups, but they must be tailored to fit each individual rig's specific requirements.

Well Control While Tripping

The decision tree **"Jackup Well Control Procedures - Tripping – FORM B"** outlines the procedures to be used in the event that a kick is taken while tripping. These procedures are intended to be general in order to cover all jackups, but they must be tailored to fit each individual rig's specific requirements.

Responsibilities

Area Manager: Approves well control procedures which differ from SeaDrill procedures.

OIM: Responsible for the overall safety of the rig and the strict adherence to procedures. Ensures that the crews are properly trained and drills are performed regularly.

Rig Superintendent/Toolpusher: Ensures that the BOP equipment is properly maintained and used.

Driller: First line of defense to shut the well in; monitors the hole for early signs of flow; must be familiar with SeaDrill and Operator's Procedures and policies.

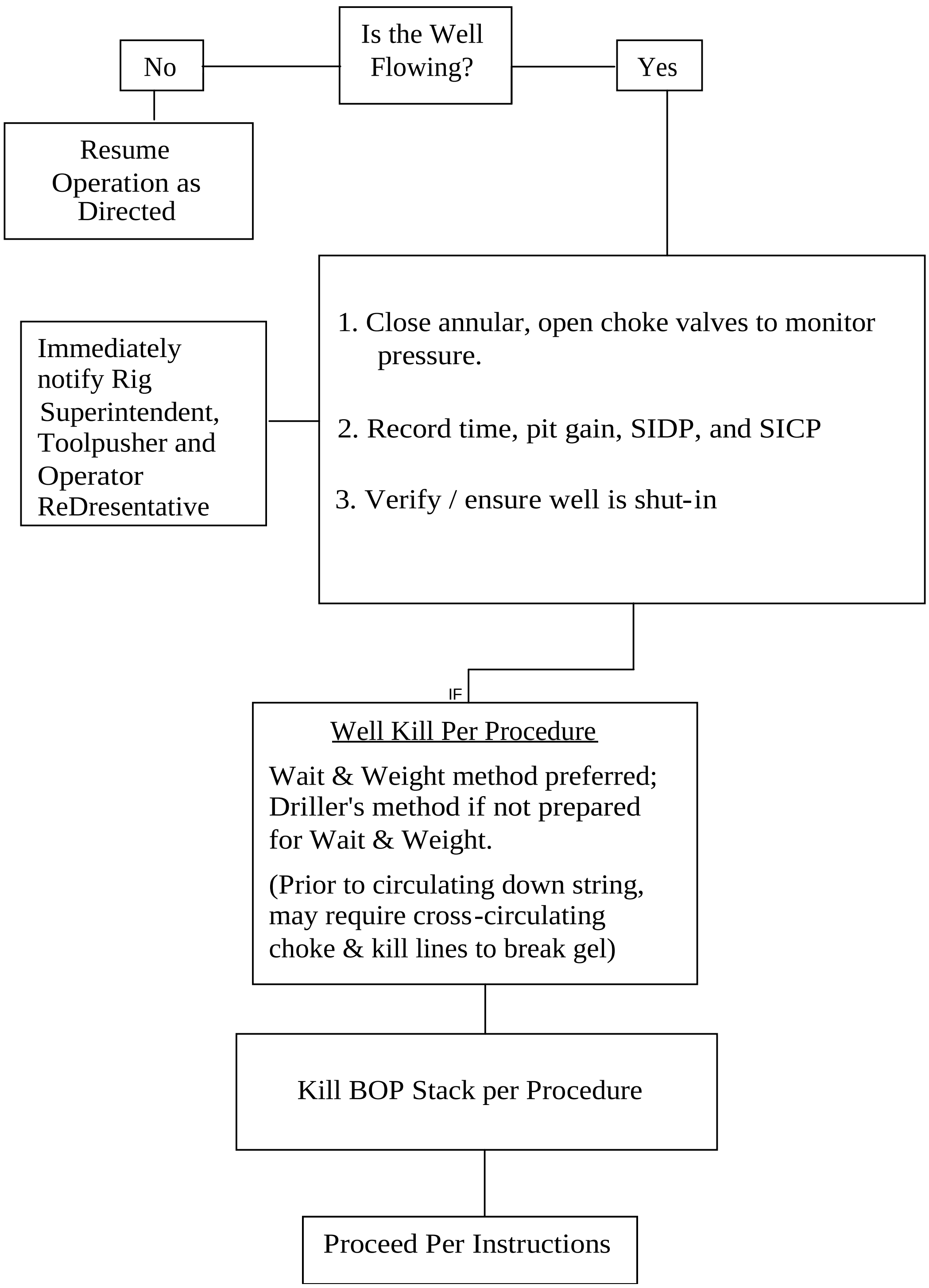
Operator: Provides information, instructions and safety procedures and precautions for Operator's supplied materials and services.

References

MODU Operation Manual
Operator Well Control Procedures Manual

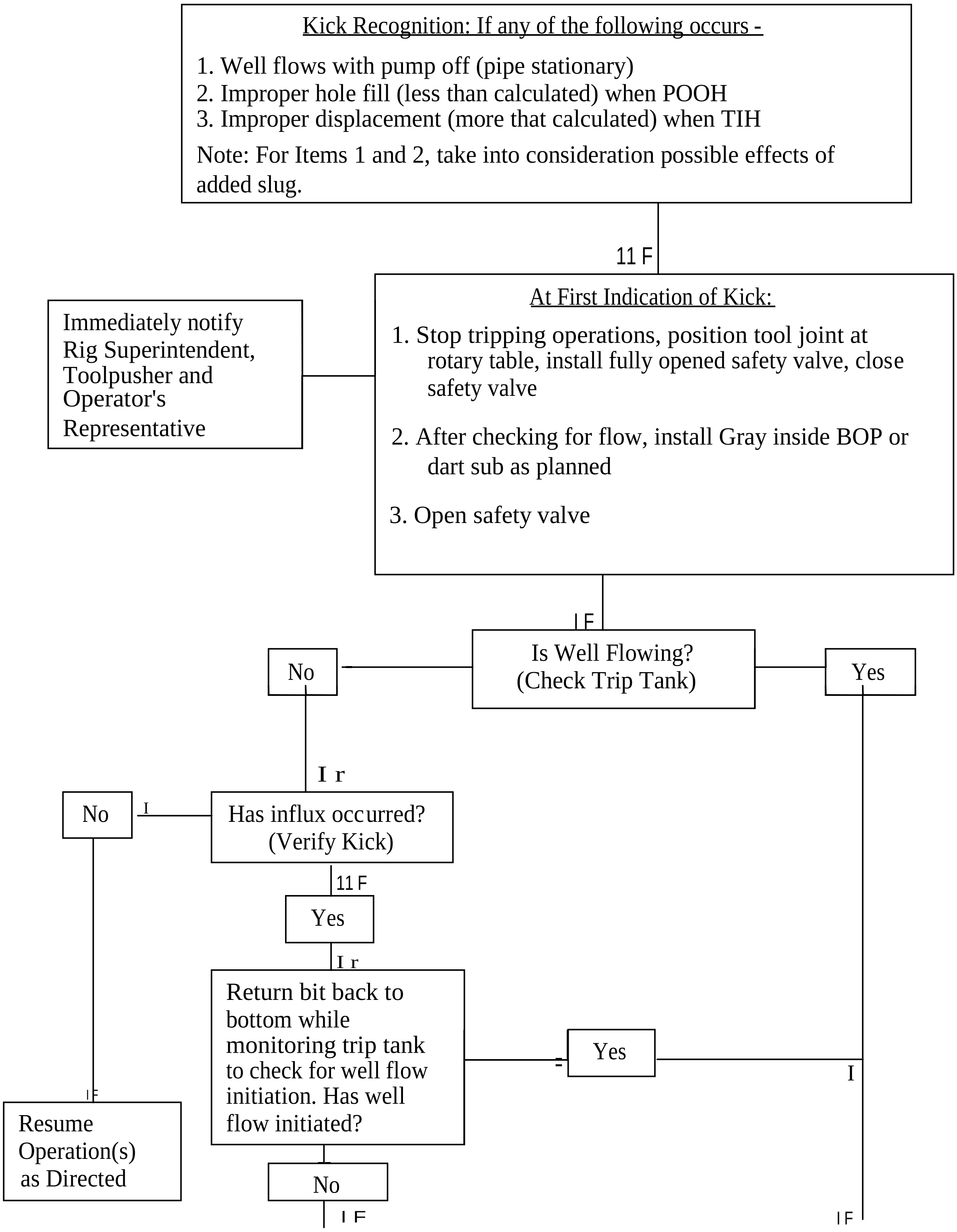
Note: It is recognized that each mobile offshore drilling unit (MODU) is different from others with respect to equipment specifications and designed layout. The intent of this system is to provide the basics for each procedure, with special emphasis on the safety and environmental aspects of the tasks to be performed. It is the obligation of each MODU to use these generic procedures as a guide to complete a Job Safety Analysis (JSA) that will become that MODU's rig-specific procedure.

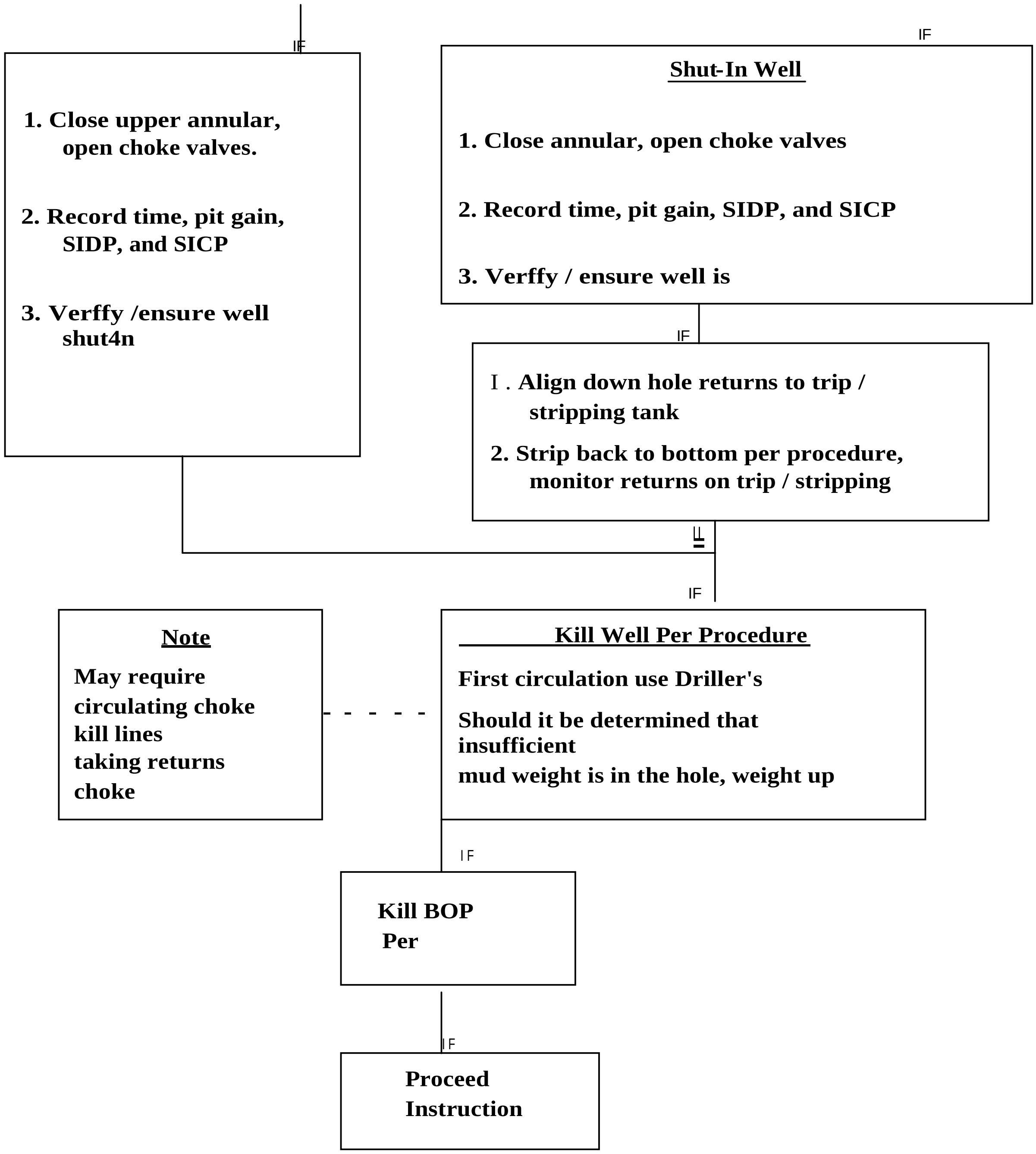
JACKUP WELL CONTROL PROCEDURES – DRILLING (FORM A)



JACKUP WELL CONTROL PROCEDURES – TRIPPING (FORM B)

Preferred Procedure: Hard Shut-In





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SHALLOW GAS PROCEDURES - JACKUP

Objective

To properly plan for the possibility of a shallow gas event in order to protect personnel, equipment and the environment.

Background

Encountering shallow gas can be a serious problem when spudding the well before the BOP has been set, when only a short casing string has been set, or when drilling an open-hole section prior to setting a long protective string. Gas can quickly reach the surface with little warning because the hole is shallow. When the BOP stack is in place, the failure of a weak casing string or weak formations may allow shallow gas to broach to the sea floor. Semisubmersibles are capable of rapidly moving off location, but Jackups do not have that option If the BOP or riser is not in place, the only possibility to control the flow is to fill the annulus with kill mud.

Pre-Planning

Ensure that there is complete agreement with the Operator's Representative on how a shallow gas kick will be handled if it is encountered.

The "Driller's Instructions for Shallow Gas Well Control" shall be posted on the drill floor prior to commencing operations on the well. The decision to shut the well in will be based on the results of the Operators Well Plan. The Driller has the ultimate responsibility to decide if shutting the well in is safe under the given conditions.

Handling a shallow gas kick requires immediate action to prevent the situation from getting out of hand. It is important that all personnel involved become familiar with the contents of this procedure. The OIM/Rig Superintendent and the Operator's Representative should brief the crews on their role on how to handle a shallow gas situation prior to spudding the well.

If the well starts to flow, the Driller shall immediately shut in or divert the well as approved in the Operators Well Plan. The OIM, Rig Superintendent and the Operators Representative shall be notified immediately of the situation.

Safety Precautions

- Extra care is required to ensure the safety of new personnel.
- If the rig is equipped with a diverter system, the diverter packer must always be in place and locked down when drill pipe is in the hole.
- Safety equipment must be tested and ready for use.
- Ensure that the diverter has been completely tested and that the knife valves operate properly to line up the diverter line in either direction prior to spudding the well.

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- Record (each watch) the direction of wind and current and the time and direction of any changes that occur.
- SeaDrill recommends that at least one reserve pit shall contain kill weight mud.
- The OIM and Company Representative must remain aware of the wind and current direction and the location of any boats around the rig while spudding the well or drilling the surface hole.

Shallow Gas Procedures with Diverter Installed on Drive Pipe

- If shallow gas is encountered, the Driller will immediately close the diverter and notify the OIM/Rig Superintendent/Toolpusher and the Operator's Representative of the situation. On their advice will line up and pump kill weight mud at the fastest rate that pressure will allow, using all available mud pumps.
- If drilling mud from the active and reserve systems is exhausted before the well is killed, seawater will be pumped while building mud volume and weight.
- If the OIM determines that the rig or personnel could be in danger from the shallow gas situation, he will make the decision concerning whether to initiate evacuation or abandonment of the rig.

Shallow Gas Procedures with Conductor Pipe Set

In some situations while drilling this section of the well, it is possible for the well to start flowing without entering an abnormally pressured shallow gas zone. This is most likely to occur due to swabbing during a trip, gas cut mud while drilling, or flow after cementing. In this situation, if the flow is detected soon enough and the conductor pipe is set at sufficient depth, it is possible to shut the well in and successfully kill it using conventional well control methods.

If shallow gas is encountered, the Driller will immediately close the well in or divert as per the **"Driller's Well Control Response with Diverter Installed"** and notify the OIM/Rig Superintendent/Toolpusher and the Operator's Representative of the situation.

- Well killing procedures will be initiated as per the well control plan.
- If the OIM determines that the rig or personnel could be in danger from the shallow gas situation, he will make the decision concerning whether to initiate evacuation or abandonment of the rig.

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Responsibilities

Operations Manager: Approves well control procedures which differ from SeaDrill procedures.

OIM: Responsible for the overall safety of the rig and its personnel.

Rig Superintendent/Tool Pusher: Ensures that the crews are properly trained and drills are performed regularly. Ensures that the BOP equipment is properly maintained and used.

Barge Supervisor: Ensures that lifeboats and liferafts are maintained in good working condition for use in abandonment operations when necessary.

Driller: Monitors the hole for early signs of shallow gas. Must be familiar with SeaDrill and Operator's Procedures and policies.

Operator: Provides information, instructions and safety procedures and precautions for Operator's supplied materials and services.

References

- SeaDrill Emergency Evacuation Plan
- SeaDrill Safety Management System
- SeaDrill Rig Operation Manual
- Operator's Site SpecificEmergency Plan
- Operator's Well Control Procedures Manual
- Operator's Well Plan

Note:. It is recognized that each mobile offshore drilling unit (MODU) is different from others with respect to equipment specifications and designed layout. The intent of this system is to provide the basics for each procedure, with special emphasis on the safety aspects of the tasks to be performed. It is the obligation of each MODU to use these generic procedures as a guide to complete a Job Safety Analysis (JSA) that will become that MODU's rig-specific procedure.

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SEADRILL JACKUPS WORKING WITH DIVERTERS
SEADRILL / Operator Surface Hole Bridging Document
Hazard Identification and Prevention

No.	Question	Response	Guidance
I	Does the Company man know you have the capability to close the well in and circulate with your diverter system?		If No, educate the Company Man on rig specific diverter capabilities.
Drive pipe only set			
2	Does the Operator plan on diverting if the well flows?		If Yes, OK. If the Operator plans to close in the well with only the drive pipe set, a MOC is required.
Drive pipe and 2nd string of casing (conductor) set and cemented (cement not cured)			
3	Does the Operator plan to hold pressure on the cement while curing?		If Yes, how much pressure? ________
4	If the well flows while Waiting on Cement, does the Operator agree to closing in the well and monitoring pressure?		If Yes, OK. If No, MOC is required.
5	Does the Operator plan to wash out the casing annulus with tubing across the diverter sealing element?		If Yes, MOC required, complete with plan to maintain sufficient hydrostatic pressure and a way to quickly remove the wash-out tubing in the event the well begins to flow.
Conductor pipe set and drilling surface hole			
6	Does the Operator agree to drill this hole section with a minimum mud weight of 9.5 ppg?		If Yes, OK. If no, MOC required. A discussion must take place with appropriate shorebased management to determine why the requested minimum mud weight can not be used. (i.e. depleted formations)
7	If the well flows a small amount (less than 50% on flo sho)with the pumps off, does the Operator agree to close in the well?		If Yes, close in and check pressures. If below Maximum allowable casing pressure, kill well using constant bottom hole method. If pressure is greater than MACP, divert well and prepare to evacuate rig. IF No, MOC is required.
8	If the well flows a large amount (greater than 50% on flo-sho) with pumps off, does the Operator agree to divert?		If Yes, Ok. If No, MOC required.

No.	Question	Response	Guidance
Conductor pipe set - Tripping			
9	Does the Operator plan to pump out of the hole to prevent swabbing?		If Yes, OK. If No, pull first 5 stands with trip tank pump off, continuously observing mud level in bell nipple. Fill each stand and record same. Toolpusher required on rig floor.
10	If well starts to flow slowly, does operator agree to close well in?		If Yes, OK. IF No, MOC required.
Surface casing (3rd string) set and cemented (cement not cured)			
I I	Does the Operator plan to hold pressure on the cement while curing?		If Yes, how much pressure? ________
12	If the well flows while Waiting on Cement, does the Operator agree to closing in the well and monitoring pressure?		If Yes, OK. If No. MOC is required.
13	Does the Operator plan to wash out the casing annulus with tubing across the diverter sealing element?		If Yes, MOC required complete with plan to maintain sufficient hydrostatic pressure and a way to quickly remove the wash out tubing in the event the well begins to flow.

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SEADRILL DIVERTING PROCEDURES - DRILLING

	ACTION TO BE TAKEN	PERSON RESPONSIBLE
1	Detect kick.	Driller
2	Place diverter control system in divert position. This will close the diverter bag and open both vent lines.	Driller
3	Position tool joint near floor and out of Diverter.	Driller
4	Close up-wind valve.	Driller
5	Notify OIM/Rig Supt. and Operator's representative that well is kicking. A decision to evacuate drill floor will be made at this time.	Backup Tong Hand
6	Notify Derrickman to switch to kill weight mud (if available) and then saltwater as needed.	Lead Tong Hand
7	Notify rig mechanic to shut down all ignition sources and prepare to shut down non-essential power.	Toolpusher / OIM
8	Driller continues to pump with mud pumps at full speed or as required to bring well under control.	Driller
9	Toolpusher and safety officer assemble all non-essential personnel at up-wind lifeboat station.	Toolpusher / SO
10	Operator's representative notifies shore base and standby boat of possible evacuation.	Operator's Rep.
I I	Evacuate drill floor and shaker area.	Toolpusher / Driller
12	Monitor rig condition for possible evacuation. Post bubble watch around rig.	Toolpusher / Driller
13	Evacuate non-essential personnel by safest means possible	0IM
14	Evacuate rig as required. All power will be shut down if rig is evacuated. The decision to evacuate will be made by the 01M.	0IM

SEADRILL JACKUP DIVERTING PROCEDURES - TRIPPING

	ACTION TO BE TAKEN	PERSON RESPONSIBLE
I	Detect kick.	Driller
2	Stab drill pipe T1W valve. (When drilling with a top drive it may be possible to slack off and make up top drive to pipe if connections are compatible.	Lead and Backup Tong Hand
3	Position tool joint near floor and out of BOPs.	Driller
4	Place diverter control system in divert position.	Driller
5	Close up-wind valve.	Driller
6	Notify Toolpusher and Operator's Representative that well is kicking. A decision to pick up the kelly or evacuate drill floor will be made at this time.	Backup Tong Hand
7	Pick up the kelly/Make-up Top drive NOTE: The decision to pick up the kelly or make -up top drive will be based on the severity of the kick and the potential hazards to the crew.	Driller
8	Notify Derrickman to switch to kill weight mud (if available) and then saltwater as needed.	Lead Tong Hand
9	Toolpusher is to notify rig mechanic to shut down all ignition sources and prepare to shut down non-essential power.	Toolpusher / OIM
10	Driller continues to pump with mud pumps at full speed or as required to bring well under control.	Driller
I I	Toolpusher and Safety Officer assemble all non-essential personnel	Toolpusher / SO
12	Operator's representative notifies shore base and standby boat of possible evacuation.	Operator's Rep.
13	Evacuate drill floor and shaker area.	Toolpusher / Driller
14	Monitor rig condition for possible evacuation. Post bubble watch.	Toolpusher
15	Evacuate non-essential personnel by safest means possible	OIM
16	Evacuate rig as required. All power will be shut down if rig is evacuated. The decision to evacuate will be made by the 01M.	OIM

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Date updated__________

DRILLER'S WELL CONTROL RESPONSES WITH DIVERTER INSTALLED

For this ________ inch hole section and next ________inch casing run:

(circle one)

If the well flows while		
Greater than 50% on Flo-Sho	Close	Divert
Less than 50% on Flo-Sho	Close	Divert
If the well flows while	Close	Divert
If the well flows after cementing:	Close	Divert
If the well flows while Waiting On Cement:	Close	Divert

Maximum Allowed Casing Pressure (per DODI chart or LOT) psi.

Note: If Maximum Allowed Casing Pressure is exceeded on initial shut in, Divert and prepare

WELL CONTROL TRAINING - JACKUP

Objective

To ensure that the training conducted to prepare for well control situations on a SeaDrill jackup is carried out in an efficient manner according to an agreed procedure so that the knowledge gained results in a minimum of risk to personnel, equipment and the environment,

Scope

This procedure applies to training in preparation for well control situations on all SeaDrill Jackup rigs worldwide.

Pre-Planning

1. Well control training covers well control training courses and well control drills.
2. Drills shall only be conducted when the bit is above the casing shoe and the well is stable.
3. Obtain relevant information from the Operator and agree on a specific procedure to be used for the drill.

Safety Precautions

- Extra care and attention are required to ensure the safety of new or inexperienced personnel.
- Ensure that individual members of the drill crew are given specific functions to perform for each type of drill to be conducted and that they are familiar with their assignments.
- The rig crew shall be trained to wait for help during a drill when another member of the team is not immediately available. This will eliminate injuries resulting from straining to lift or move a load that should not be attempted without additional help in an effort to complete the drill within the pre-determined time limit. It is better to take a time penalty for the drill than to cause an injury.
- Completing a drill within a prescribed time limit must result from teamwork and efficiency - not simply from demands for speed. Hurrying creates injuries but controlled practice creates efficiency.

Well Control Training Course Requirements

1 Members of the drill crew on a Seadrill Jackup must be trained in accordance with the provisions of the relevant government policy and the Seadrill requiremnts in the training manual. IWCF will be the accredited training forum.

2. Well control certification must be renewed every 2 years.

Well Control Drill Requirements

Drills must be carried out in accordance with relevant legislation or in accordance with the well program. The following are the minimum drill requirements for well control safety for rigs working in international waters.

1. A well control drill plan must be prepared for each crew member showing his assignment for the drill and giving the prescribed time for the completion of each portion of the drill. This drill plan must be posted on the drill floor.
2. The Rig Superintendent/Toolpusher will initiate drills by raising the float on the pit level device or activating the mud return indicator to show that an abnormal situation has been simulated to start the drill.
3. Drills will be carried out as appropriate and under varying situations but should not be initiated while drilling or tripping in open hole.
4. Drills will take the form of the Kick Control Procedures or Trip Drills and will be carried out through the step of closing the choke on the choke manifold to record pressures.
5. Each crew will be drilled at least weekly in one of the situations which could be encountered while conducting drilling or tripping operations such as trip drills, pit drills, stripping in, maintaining constant bottom hole pressure using the volumetric method, diverter drills, shallow gas drills, etc. These drills will be varied to familiarize crews with differing situations. Drills will be repeated or performed more frequently if necessary to maintain the crew's alertness and ensure that all crews are competent and familiar with all aspects of handling a potential well control situation.

Responsibilities

OIM: Responsible for the overall safety of the rig and its personnel.

Rig Superintendent/Toolpusher: Ensures that the crews are properly trained and drills are performed regularly and properly. Ensures that the BOP equipment is properly maintained and used.

Driller: Carries out the steps required by the drill to train the crews. Must be familiar with SeaDrill and Operator's Procedures and policies.

Operator: Provides information, instructions and safety procedures and precautions for Operator's supplied materials and services.

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References

SeaDrill Safety Management System
Rig Operation Manual
Operators Well Control Procedures Manual
Operator's Well Plan

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WAITING ON CEMENT - SURFACE STACKS

Objective

The objective of this guideline is to make sure that SeaDrill safely provides the best service possible to its customers during cementing operations without exposing personnel, equipment or the environment to unnecessary risks or hazards.

Background

Over the past several years there has been considerable confusion regarding whether or not to wait on cement prior to removing well control equipment. There are many documented cases where removal of the BOP equipment at the wrong time resulted in blowouts and rig fires. This guideline is intended to provide guidance based on the best information available to date provided by the cementing experts.. As new technology and information become available, this guideline will be updated.

This Waiting-on-Cement Guideline and associated Waiting-on-Cement Decision Tree are to be referenced for guidance when deciding whether or not to wait on cement and for how long to wait. Deviations from this guideline are permissible **only** with approval from the General Manager.

This guideline must be discussed well in advance with customers, preferably in the pre-spud meeting or earlier, so that necessary information for decision making may be obtained in a timely manner.

There may be other down hole conditions that could modify the guideline outlined below, such as the complete loss of returns while pumping cement. In this case, confidence in the cement job would be decreased and waiting for a full 8 hours is deemed prudent. As an additional example, a cement job is started even though the hole has not been circulated free of gas after running casing. Here again it would be a good practice to wait the full 8 hours. When in doubt, discussions with the company representative and the Operations Manager are required prior to removing the BOP equipment.

WOC Well Control Event Log

In order to document incidents of well control situations resulting from cementing operations and to share this information with the international fleet, a **WOC Well Control Event Log** has been designed. The log is in Excel format and can be completed on screen and printed, or forwarded by E-mail. It can also be saved to your hard drive for future reference or review.

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WOC Decision Tree Procedures

For normal operations, and in the interest of safety, the following guideline and associated **WOC Decision Tree** define minimum waiting-on-cement times:

Step 1:

Determine whether hydrocarbon zones exist in the open hole section of the wellbore.

- If it is KNOWN by using MWD/LWD/wireline logging tools that no hydrocarbon zones exist in the open hole, or that the zones identified have low permeability with little to no flow potential, it is not necessary to wait-on-cement after bumping the plug. In this case, go to **Step 4.**

- If the presence of hydrocarbon zones cannot be determined within the open hole section of the wellbore, or have been found but with unknown flow potential, go to **Step** 2.

Step 2:

Once cement pumping is complete and the plug has been bumped, waiting-on-cement time required is determined as follows (See Note 1. If this the case, go to Step 4):

1st Level or Primary Decision (Use if the 500-lb/100-ft^2 gel strength data is known)

The primary decision criteria for determining when this time is completed is when the cement reaches 500-lb/100-& gel strength (See Note 2). This will occur once Job-Placement-Time, Zero-Gel-Time and Transition-Time have elapsed. It has been determined (Ref: Halliburton Energy Services) that once the cement gel strength reaches 500-lb/100-ftz gel strength, the chance of gas channeling through the cement is minimal. Go to Step 3.

3rd Level or Secondary Decision (Use if the 50-psi compressive strength data is known but gel strength data not known)

Should the primary decision information (500-lb/100-ft^z gel strength) not be available then the secondary method for determining waiting-on-cement time is when the in-place cement reaches 50-psi compressive strength (See Notes 2 and 3). This WOC time value exceeds the time for obtaining the 500-lb/100-& gel strength, therefore erring on the safe side. Go to Step 3.

3rd Level or Tertiary Decision (Use if neither gel strength nor compressive strength data is known)

If unable to obtain gel strength or compressive strength data for the proposed cement slurry or if unable to <u>confirm</u> NO hydrocarbon zones in the open hole section of the wellbore, wait-on cement time is to be 8 hours (See **Note 4).** Go to **Step 3.**

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Step 3:

Once the wait-on-cement time in hours is obtained for the specific cement slurry, you **MUST** wait-on-cement for that amount of time prior to removing the BOP equipment. **It is expected however, that preparation work or other critical path operations would be completed during this wait-on-cement time in an effort to minimize flat time. Go to Step 4.**

Step 4:

After making sure the annulus is full, proceed according to the planned procedures of the Operator (may include nippling down the stack).

Notes:

1) Nippling down when waiting-on-cement becomes a non-issue when the well head can accommodate pressure containment. Two examples come to mind:

   - For low pressure wellheads (generally 5M or less), when dropping elastomer slips on API well heads and containment is achieved; and

   - For higher pressured wellheads (generally 5M and up), when using a multi-bowl system with a mandrel hanger and pack-off for achieving pressure containment.

2) This primary and or secondary decision information should have been requested from our customers long before the cement job commences, preferably at the pre-spud meeting or beforehand. It may be possible for the Operator to modify the slurry mixture and have it re-tested to minimize WOC time. If you do not have this information several days prior to the cement job, ask for it via the company representative. The Operations Managers will also be able to assist in obtaining the information through their contacts onshore.

3) The cement companies report that once the cement reaches 50-psi compressive strength, gas generally can no longer migrate through the cement slurry. This 50-psi compressive strength value is therefore conservative and should take into account variables that can not be reproduced in the laboratory. However, the reported compressive strength times may be in significant error if the temperature used for testing differs significantly from the zone of interest actual temperature. Higher testing temperatures reduce the reported compressive strength set times. This situation may lead to nippling down early and should be questioned.

4) This value was chosen based on thousands of cementing tests conducted in the laboratory by one of the primary cement suppliers. Test results indicate that the vast majority of cement slurries reach 50-psi compressive strength within the 8 hour timeframe. As can be seen, it is much better to obtain the proper cementing information and KNOW when the cement slurry reaches the appropriate WOC value rather than resorting to a rule of thumb measurement.

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Nitrogen Aerated Cement (Foam Cement)

Special considerations will be taken when utilizing foam cement on Jackups.

1) SeaDrill requires a complete risk assessment to be completed prior to utilizing foam cement on jackups, and will make sure that the results of this assessment are communicated in the cementing plan.

2) SeaDrill prohibits the running of tubing in the annulus between the casing and the diverter, or BOP, prior to completion of cementing operations and determining that the well is static. Any deviation from this prohibition will be handled by Management of Change Procedures, and will be on a case by case basis.

3) SeaDrill will verify that hydrostatic pressure calculations are performed to ensure sufficient hydrostatic head throughout the well prior to washing out to the mud line suspension hanger (MLSH).

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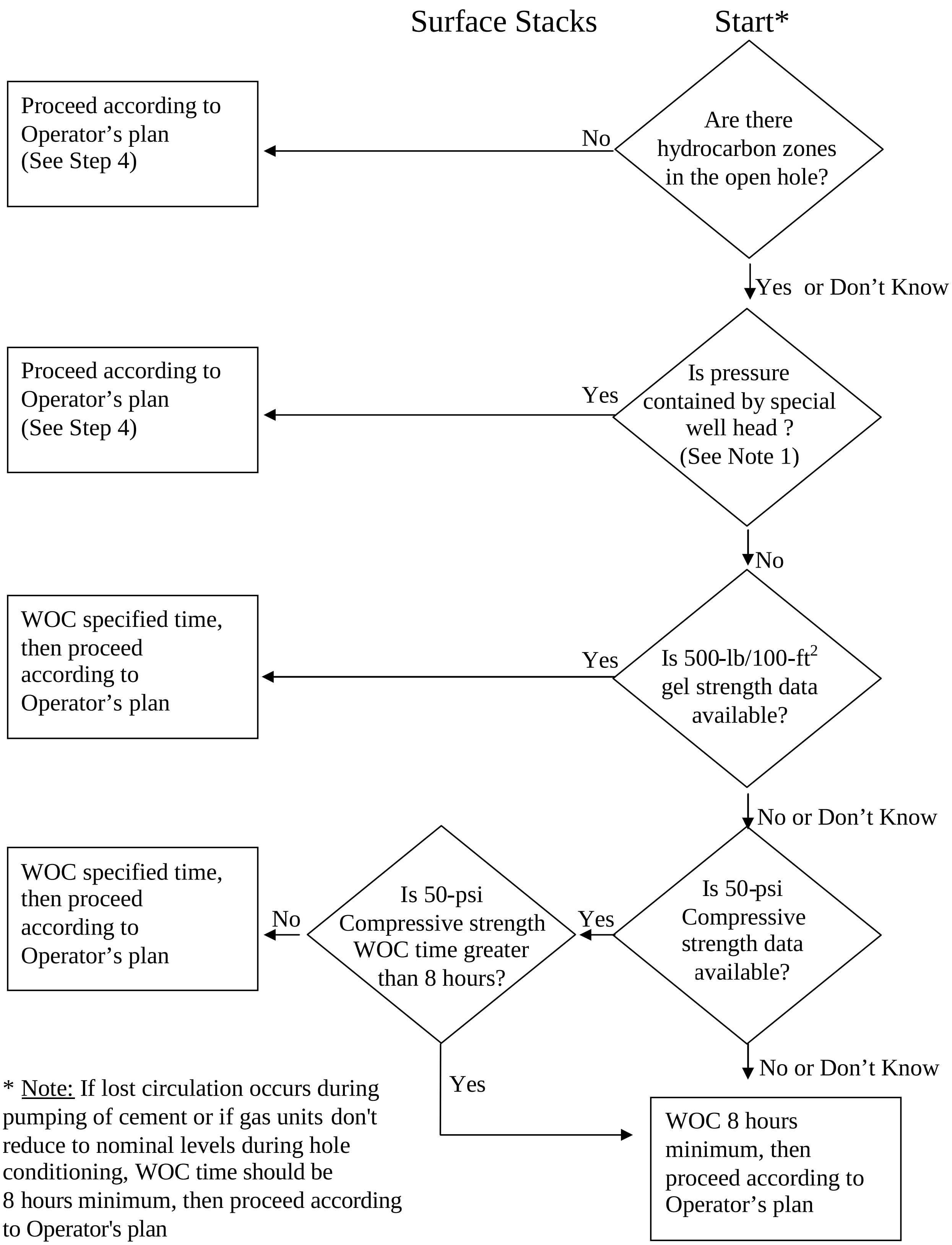
WOC DECISION TREE

Surface Stacks



* Note: If lost circulation occurs during pumping of cement or if gas units don't reduce to nominal levels during hole conditioning, WOC time should be 8 hours minimum, then proceed according to Operator's plan

WOC EVENT LOG

WAITING-ON-CEMENT

WELL CONTROL EVENT LOG

Rig: ____________ Rig Contact: ____________

Well Location: ____________ Water Depth: ____________

Date of Event: ____________ Time of Event: ____________

Customer: ____________ Customer Contact: ____________

WELL AND MUD INFORMATION

TVD - ________ ft Mud Type - ____________

MD - ________ ft Mud Weight (ppg) - ____________

Open Hole Length - ________ ft Viscosity (cps) - ____________

Open Hole Diameter - ________ in.

Max Gas Units w/ Drilling - ____________ ☐ Increasing ☐ Decreasing ☐ Staying the Same

Was a hydrocarbon zone known to be in the open hole section prior to running casing and cementing? ☐ Yes ☐ No

If yes, at what depth (ft) ____________ ☐ T V D ☐ M D

Full bottoms-up circulated prior to running casing? ☐ Yes ☐ No

If No, why? ____________________________

If yes, any gas shows? No ☐ If Yes, Gas Units ____________

Pore Pressure Plot Available? No ☐ Yes (Attach plot or data)

CASING / LINER DATA

Size - ________ in.

Grade - ________

Weight - ________ lb/ft

Top Csg/Liner - ________ ft TVD/MD

Shoe Depth - ________ ft TVD/MD

WELLHEAD EQUIPMENT DATA: (Check)

☐ Diverter (Size, rating, etc.) ____________

☐ 13 5/8 in. BOP Stack ____________ psi

☐ 16 3/4 in. BOP Stack ____________ psi

☐ Other ____________

CEMENT DATA

Cement Supplier: ____________________

Lot or Slurry Identification No.: ____________ Slurry Density: ____________

Cement laboratory test data: (Attach test data sheet if available)

Time to reach 500-lb/100ft2 gel strength - ____________

Time to reach 50 psi compressive strength - ____________

Designed placement time - ____________

Designed start time for transition - ____________

Designed length of transitions time -

CEMENT PLACEMENT DATA

Time started pumping - ________ Pumping time - ____________

Volume pumped - ________

Strokes pumped - ________ Pump capacity - ____________

Pre-sweep slurry - ________

Volume - ________

Fluid properties (density, viscosity, etc.) - ____________________

Description of slurry and cement placement: (Tops of slurry and cement, returns identified, etc.)

FLOW INFORMATION

Observed indicators of well flow when detected: (how noticed and be specific)

How long was cement was in place before flowing? ____________

Was there a surface sample and what were its characteristics at time of flow detection? ☐ Yes ☐ No

What remedial action was taken to mitigate the problem? (Be specific: diverted, shut-in with what pressures showing, action taken, time resolved, etc.)

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Seadrill

APPENDICES

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APPENDIX A

TERMS AND ABBREVIATIONS

BBL	Barrels
BHA	Bottom Hole Assembly
BHP	Bottom Hole Pressure
BOP	Blowout Prevention
CLF	Choke Line Friction
CO_2	Carbon Dioxide
CSON	Continental Shelf Operations Notice
ECD	Equivalent Circulating Density
EMW	Equivalent Mud Weight
FCP	Final Circulating Material
H_2S	Hydrogen Sulphide
HDIS	Hydril Drop In Sub
HP	High Pressure
HT	High Temperature
HWDP	Heavy Weight Drill Pipe
IADC	International Association of Drilling Contractors
IBOP	Inside Blow Out Preventer
ICP	Initial Circulating Pressure
ID	Inside Diameter
KR	Kill Rates
LCM	Loss Circulation Material
LMRP	Lower Marine Riser Package
MAASP	Maximum Allowable Annular Surface Pressure
MACP	Maximum Allowable Casing Pressure
MD	Measured Depth
MSS	Multi Shot Survey
MW	Mud Weight
OBM	Oil Based Mud
OD	Outside Diameter
OIM	Offshore Installation Manager
PPG	Pounds per gallon
PSI	Pounds per square inch
PVT	Pit Volume Totaliser
ROP	Rate of Penetration
ROV	Remote Operational Vehicle
SCR	Slow Circulating Rates
SG	Specific Gravity
SI	Statutory Instrument
SIDPP	Shut in Drill Pipe Pressure
SPM	Strokes per minute
SPR	Slow Pump Rates
TD	Theoretical Depth
TVD	True Vertical Depth

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APPENDIX B

TRIP RECORD

DATE: ..../......../........ **DEPTH:** ______________________ **WELL:** _________________________

DRILL PIPE: **Size:** ___________ **DRILL COLLARS:** **Size:** ___________

Weight: ___________ **Weight:** ___________

DISPLACEMENT: ___________ **DISPLACEMENT:** ___________

NUMBER STANDS	THEORETICAL DISPLACEMENT	TRIP TANK	ACTUAL DISPLACEMENT	ACCUMULATIVE DISPLACEMENT

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APPENDIX C

1. **WELL CONTROL KILL SHEET SUBSEA**

2. **WELL CONTROL KILL SHEET SURFACE**

SEE ATTACHED DOCUMENTS

SEA.009.001.0855

IWCF CERTIFICATION TEST
SUBSEA BOP KILL SHEET

DATE : ____________________

NAME : ____________________

UNITS : FIELD

FORMATION STRENGTH DATA:

SURFACE LEAK-OFF PRESSURE FROM
FORMATION STRENGTH TEST (A) ______ psi

DRILLING FLUID DENS. AT TEST (B) ______ ppg

MAX. ALLOWABLE DRILLING FLUID DENSITY =
(A) psi ÷ 0.05 ÷ SHOE TVD + (B) ppg = (C) ppg
_________ ÷ 0.05 ÷ _________ + _________ = (C) _____

INITIAL MAASP = ((C) ppg - CURR DENS) x SHOE TVD x 0.05
= (_________ - _________) x _________ x 0.05
= _____________ psi

CURRENT WELL DATA:

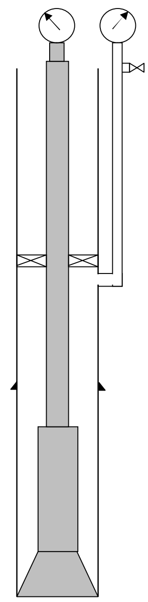
MARINE RISER
LENGTH ______ ft

CHOKELINE
LENGTH ______ ft

DRILLING FLUID DATA
DENSITY ______ ppg
GRADIENT ______ psi/ft

CASING & SHOE DATA
SIZE ______ in
M. DEPT ______ ft
T.V. DEPT ______ ft

HOLE DATA
SIZE ______ in
M. DEPTH ______ ft
T.V. DEPTH ______ ft



PUMP NO. 1 DISPL	PUMP NO. 2 DISPL
bbl / stk	bbl / stk

SLOW PUMP RATE DATA	DYNAMIC PRESSURE LOSS psi					
	PUMP NO. 1			PUMP NO. 2		
	RISER	CHOKELINE	CL. FRICT	RISER	CHOKELINE	CL. FRICT
SPM						
SPM						

PRE-RECORDED VOLUME DATA :	LENGTH ft		CAPACITY bbl / ft		VOLUME bbl	PUMP STROKES stks	TIME minutes
						VOLUME / PUMP DISPLACEMENT	PUMP STROKES / SLOW PUMP RATE
DRILL PIPE		x		=			
HEVI WATE		x		=	+		
DRILL COLLAR		x		=	+		
DRILL STRING VOLUME					(D) bbl	(E) stks	min
DC x OPEN HOLE		x		=			
DP/HWDP x OPEN HOLE		x		=	+		
OPEN HOLE VOLUME					(F) bbl	stks	min
DP x CASING		x		=	(G) +	stks	min
CHOKELINE		x		=	(H) +	stks	min
TOTAL ANNULUS / CHOKELINE VOL.	(F + G+ H)			=	(I) bbl	stks	min
TOTAL WELL SYSTEM VOLUME			(D + I) = (J)		bbl	stks	min
ACTIVE SURFACE VOLUME			(K)		bbl	stks	
TOTAL ACTIVE FLUID SYSTEM			(J + K)		bbl	stks	
MARINE RISER x DP		x		=	bbl	stks	

CALCULATIONS CAN BE MADE USING EITHER DRILLING FLUID DENSITY OR DRILLING FLUID GRADIENT

IWCF CERTIFICATION TEST
SUBSEA BOP KILL SHEET

DATE : ____________

NAME : ____________

UNITS : FIELD

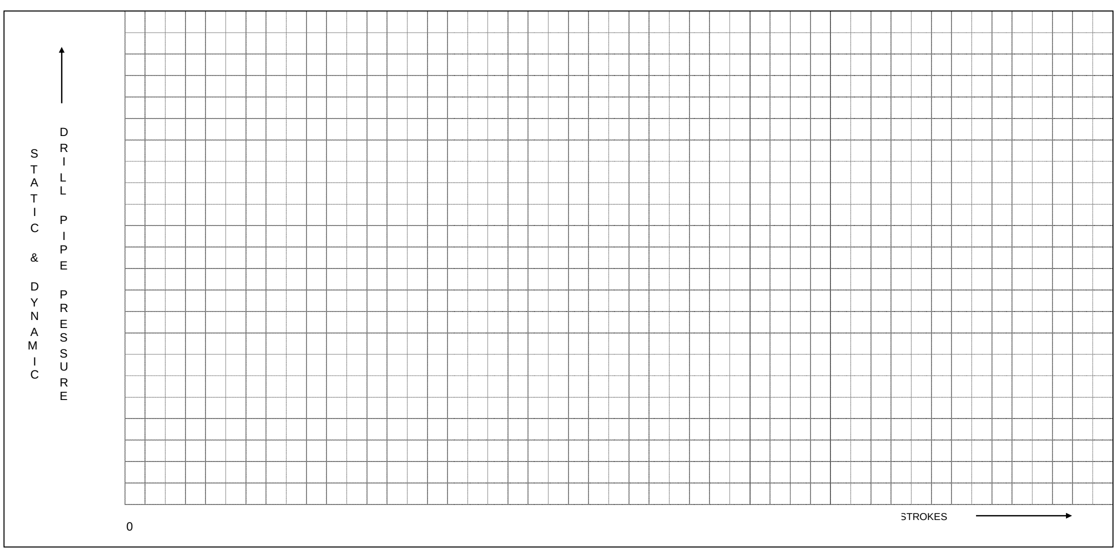
KICK DATA:

SHUT IN DRILL PIPE PRESSURE -------- SIDPP		psi
SHUT IN CASING PRESSURE -------- SICP		psi
PH GAIN		bbl

1 bbl = 42 US gall

KILL FLUID DENSITY	SIDPP ÷ TVD ÷ 0.052 + CURRENT DRILLING FLUID DENSITY ______ ÷ ______ ÷ 0.052 + ______ppg = ______ppg
KILL FLUID GRADIENT	CURRENT DRILLING FLUID GRADIENT + SIDPP / TVD ______ + ... / .... = ______psi / ft
INITIAL CIRCULATING PRESS. ICP	DYNAMIC PRESSURE LOSS THROUGH RISER CIRCUIT + SIDPP ______ + ______ = ______psi
INITIAL DYNAMIC CASING PRESS AT KILL PUMP RATE	SICP - CHOKE LINE FRICTION ______ - ______ = ______psi
FINAL CIRCULATING PRESS FCP	KILL FLUID DENSITY / CURRENT DRILLING FLUID DENSITY x DYN. PRESS. LOSS RISER CIRC. .... / .... x ______ = ______psi
FINAL CIRCULATING PRESS. FCP	KILL FLUID GRADIENT / CURRENT DRILLING FLUID DENSITY x DYN. PRESS. LOSS RISER CIRC. .... / .... x ______ = ______psi
(L) = ICP - FCP = ______ - ______ = ______psi	(L) x 100 / (E) = ... x 100 / .... = ______ psi / 100 strokes

STROKES	PRESSURE



IWCF CERTIFICATION TEST
SURFACE BOP KILL SHEET

DATE: ______________________________
NAME: ______________________________
UNITS: FIELD

FORMATION STRENGHT DATA

SURFACE LEAK-OFF PRESSURE FROM FORMATION STREGHT TEST		psi
DRILLING FLUID DENSITY AT TEST		sg
MAX ALLOWABLE DRILLING FLUID DENSITY		sg
INITIAL MAASP		psi

PUMP NO. DISPLACEMENT		PUMP NO. DISPLACEMENT	
12.46	l/stk		l/stk

SLOW PUMP RATE DATA	DYNAMIC PRESSURE LOSS	
	PUMP NO.	PUMP NO.
SPM	psi	psi
SPM	psi	psi

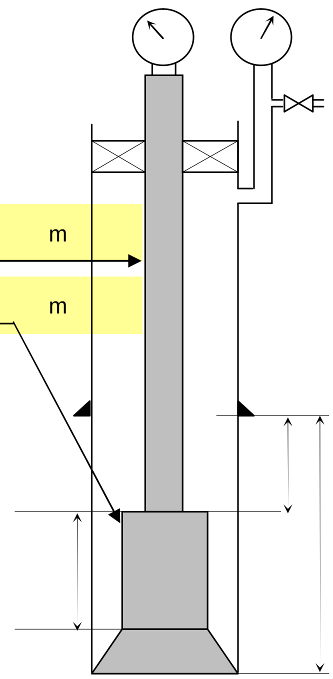
CURRENT WELL DATA

DRILLING FLUID DATA

DENSITY		sg
GRADIENT		bar/m

DP m

DC m



CASING AND SHOE DATA

SIZE		in
M. DEPTH		m
T.V. DEPTH		m

HOLE DATA

SIZE		in
M. DEPTH		m
T.V. DEPTH		m

PRE-RECORDED VOLUME DATA	LENGTH m	CAPACITY l / m	VOLUME L	PUMP STROKES stks	TIME minutes
				VOLUME / PUMP DISPL.	PUMP STROKES / SLOW PUM RATE
DRILL PIPE	x	=	+		
HEVI WATE	x	=	+		
DRILL COLLAR	x	=	=		
DRILL STRING VOLUME			(D) L	(E) stks	min
DC x OPEN HOLE	x	=	+		
HW x OPEN HOLE	x	=	+		
DP x OPEN HOLE	x	=	=		
OPEN HOLE VOLUME			(F) L	stks	min
DP x CASING	x	=(G)	L	stks	min
TOTAL ANNULUS VOLUME		(F+G)=(H)	L	stks	min
TOTAL WELL SYSTEM VOLUME		(D+H)=(I)	L	stks	min
ACTIVE SURFACE VOLUME		(J)=	L	stks	
TOTAL ACTIVE FLUID SYSTEM		(I+J)=	L	stks	

CALCULATIONS CAN BE MADE USING EITHER DRILLING FLUID DENSITY OR DRILLING FLUID GRADIENT

IWCF CERTIFICATION TEST
SURFACE BOP KILL SHEET

DATE: ______________________
NAME: ______________________
UNITS: FIELD

KIK DATA

SHUT IN DRILL PIPES PRESSURE	SIDPP		bar
SHUT IN DRILL CASING PRESSURE	SICP		bar
PIT GAIN			L

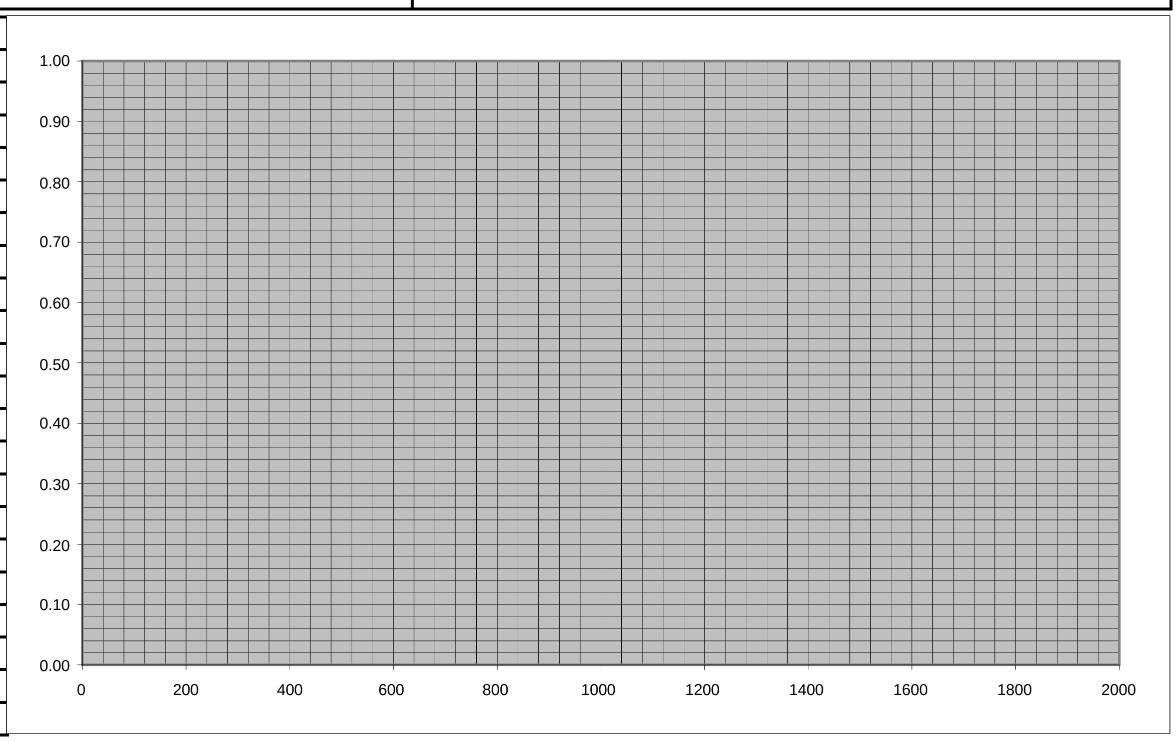
KILL FLUID DENSITY	CURRENT DRILLING FLUID DENSITY + SIDPP x 10.2 / TVD ------------ + ------------ x 10.2 / ------------ = ------------ bar
KILL FLUID GRADIENT	CURRENT DRILLING FLUID GRADIENT + SIDPP / TVD ------------ + ------------ / ------------ = ------------ bar / m

INITIAL CIRCULATING PRESS. ICP	DYNAMIC PRESSURE LOSS + SIDPP ------------ + ------------ = ------------ bar
FINAL CIRCULATING PRESS. FCP	KILL FLUID DENSITY / CURRENT DRILLING FLUID DENSITY x DINAMIC PRESSURE LOSS ------------ / ------------ x ------------ = ------------ bar

(K) = ICP - FCP = ---------- - ---------- = ---------- psi

(K) x 100 / (E) = ---------- x 100 / ---------- = ---------- psi/100strokes

STROKES	PRESSURE



IWCF KILL SHEET Surface

INTERMEDIATE DRILL PIPE PRESSURE

ICP =		Initial circulating pressure, psi
FCP =		Final circulating pressure, psi
$Strokes_{total}$ =		Total number of strokes
$Strokes_{sel}$ =		Selected number of strokes

IDPP = ____________ **Intermediate drill pipe pressure, psi**

PRESSURE CHART

To fill in the pressure chart calculate the incremental steps using the formulas at the bottom of the chart

	PRESSURE CHART		
	STROKES	PRESSURE	
			← ICP
BIT →			← FCP

Surface to Bit Strokes ÷ 10 = Strokes per Step | ICP - FCP = PSI DROP ÷ 10 = PSI per Step

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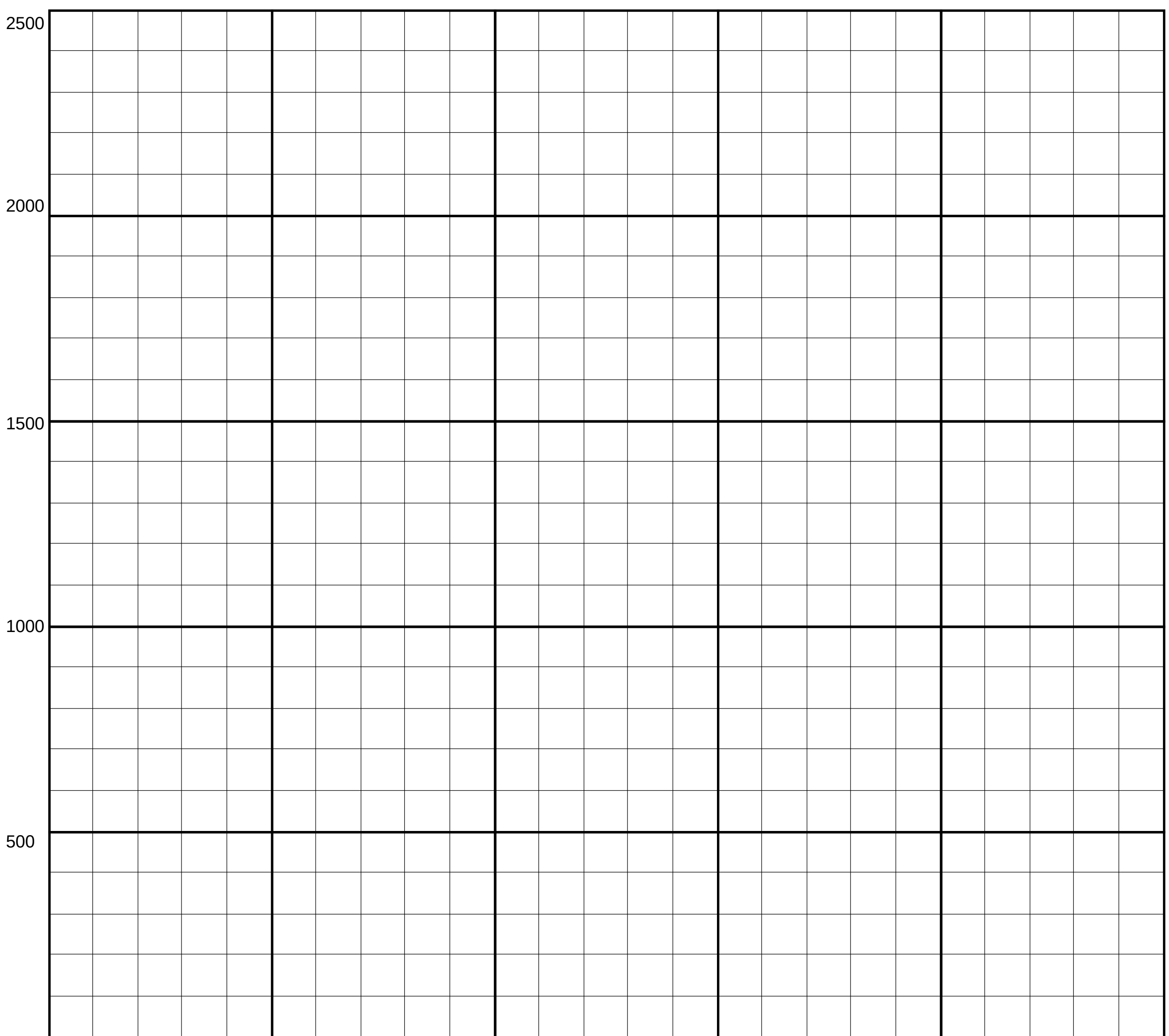
PRESSURE GRAPH

The pressure graph is completed by graphing Initial Circulating Pressure and Final Circulating Pressure against time or strokes. The cahrt may then be filled out using information extrapolated from the graph, or by using the formuulas for the pressure chart

DRILL PIPE PRESSURE SCHEDULE



ICP												FCP
STROKES												
TIME												

Pressure Graph

IWCF CERTIFICATION TEST
SURFACE BOP KILL SHEET

DATE: ____________________________
NAME: ____________________________
UNITS: FIELD

(K) = ICP - FCP = --------------- - ---------------psi

$\frac{(K) \times 100}{(E)}$ = $\frac{\text{---------------} \times 100}{\text{---------------}}$ = --------------- psi/100strokes

STROKES	PRESSURE

STATIC & DINAMIC
DRILL PIPE PRESSURE

STROKES