Chapter 4. Health Safety and Environment

Health Safety and Environment Subcommittee

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Terms and definitions Used in Chapter 4

API	American Petroleum Institute
ALARP	As Low As Reasonably Practical
BHA	Bottom Hole Assembly
BOP	Blowout Preventer
BPM	Barrels Per Minute
BPV	Back Pressure Valve
C&K	Choke and Kill
DIV	Drillstring Induced Vibration
DP	Dynamic Positioning
ECD	Equivalent Circulating Density
FEA	Finite Element Analysis
FOSV	Full Opening Safety Valve
GMDSS	Global Maritime Distress and Safety System
GOM	Gulf of Mexico
HAZID	Hazard Identification
HAZOP	Hazard and Operability
HSE	Health Safety and Environment
IADC	International Assoc of Drilling Contractors
IBOP	Inside Blowout Preventer
MUX	Multiplexed
MWD	Measurement While Drilling
NaCL	Sodium Chloride (Salt)
OBM	Oil Based Mud
OIM	Offshore Installation Manager
OSRP	Oil Spill Response Plan
OWS	Oily Water Separator

PPG	Pounds Per Gallon
PWD	Pressure While Drilling
QRA	Quantitative Risk Assessment
RIH	Run In Hole
ROV	Remote Operated Vehicle
RTTS	Retrievable Test Treat Squeeze
SBM	Synthetic Based Mud
SBOP	Surface BOP
SBR	Shear Blind Ram
SCP	Slow Circulating Pressure
SCR	Slow Circulating Rate
SICP	Shut In Casing Pressure
SID	Seabed Isolation Device
SIDPP	Shut In Drill Pipe Pressure
SMS	Safety Management System
VBR	Variable Bore Ram
VIV	Vortex Induced Vibration
WCP	Well Control Procedure

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4.1 Introduction

This Chapter of the guideline document deals with the HSE issues relating to the use of a surface BOP drilling system. The guideline is written from the perspective of modifying and converting existing floating drilling vessels to utilize surface BOP drilling systems. However, the principles are applicable to new construction vessels with surface BOP systems also. The guiding principle when considering implementing a surface BOP drilling system is that the system and its operation should be as safe or safer than a conventional deepwater subsea drilling system.

It is recognized that all companies have HSE policies and guidelines for carrying out daily business and how to manage the risks of running that business. When retrofitting a surface BOP equipment package to an existing unit it is critical that all Health, Safety and Environment considerations are reviewed and acted on in a consistent and thorough manner. This guideline gives recommendations relating to HSE topics that other operators have considered when making use of a surface BOP system for the first time.

It is recommended that any organization anticipating making use of a surface BOP system on their Mobile Offshore Drilling Rigs should at the very least be able to develop a rig specific Safety Management System that will ensure all areas of HSE critical to the successful operation of the new equipment are fully understood. The surface

BOP Safety Management System should be developed to provide Companies with a structured approach to the design and implementation of surface BOPs in a consistent manner ensuring system integrity. Defining high-level performance standards and assurance processes should be key elements of this system, which then cascade down to detailed functional specifications. Key elements of this recommended overall Safety Management System for use with a surface BOP System are as follows;

- **Risk Assessment**

  Understanding and quantifying the risk associated with using the equipment and mitigating the risk for using that equipment.

- **Well Control**

  Understanding the capabilities, limitations and operational impact of using a surface BOP during a well control event.

- **Environmental Discharge Contingency Plans.**

  Ensuring that plans are in place to control, contain and mitigate any discharge that may be damaging to people, assets or the environment resulting from SBOP operations.

- **Emergency Response Guidelines.**

  Ensuring adequate emergency response plans are in place taking account of SBOP operations and specific system configurations and operational capabilities and limitations.

- **Planning and Preparation Guidelines**

  Ensuring consistency in the planning and preparation phase when working with a surface BOP equipment package.

- **Equipment Verification and Specification**

  Ensuring that all equipment is fit for purpose before, during, and after installation on a rig.

- **Personnel Training**

  Ensuring that all personnel associated with the surface BOP operations are adequately prepared to make use of the equipment.

It should be noted that a Safety Management System does not have to be limited to just these items and can be modified to fit existing HSE documentation.

4.2 Risk Assessment

One of the most critical areas associated with the installation and operation of a surface BOP equipment package on a floating rig relates to the risk assessment process. It is strongly recommended that a comprehensive risk assessment program be considered as a key element of any anticipated use of surface BOP equipment on a floating rig. There are many methods to address risk assessment, the ideas outlined in this section have been employed by both operators and drilling contractors to successfully make use of the surface BOP drilling techniques.

Risk management should be a constant theme throughout any SBOP operation, from conceptual planning through to implementation. The approach should be very much focussed on identifying any hazards directly related to, or indeed indirectly related to using surface BOP drilling systems, which can expose people, the environment or assets to danger.

4.2.1 Risk Assessment Process

A risk assessment process must ensure that hazards and their potential effects are fully evaluated. To do this the hazards must first be identified, assessed and then mitigation and recovery preparedness measures put in place to reduce the consequences of any remaining risk.

To achieve this, a number of tools and techniques can be used, including a Hazard Identification (HAZID) exercise, a Quantitative Risk Assessment (QRA), and a Hazard and Operability (HAZOP) identification exercise.

The HAZID process is a method to quickly and efficiently focus attention and talents of a group of individuals (team) to identify and assess hazards associated with a particular system. The team chosen for the exercise typically represents a collection of subject matter experts from various disciplines, such as engineering, safety and operations. The exercise employs the "brainstorming" technique to rapidly identify and assess potential hazards. The exercise is typically not a forum for solving issues or suggesting re-design options, however depending on the development stage of the system or concept, useful mitigation options may be suggested and captured during the exercise. The primary objectives of the HAZID are to identify potential hazards, determine relative importance of each hazard, and suggest mitigation opportunities when appropriate and necessary.

The Quantitative Risk Assessment (QRA) tool is a powerful decision-making tool that can assist in the selection of acceptable solutions to safety related issues for the introduction of surface BOP equipment. The technique can be defined as the formal and systematic approach to identifying hazards, potentially hazardous events, and estimating likelihood and consequences to people, the environment and assets, of incidents developing from these events.

In the last few years, QRA has gained a wide acceptance as a powerful tool to identify and assess the significant sources of risk and evaluate alternative risk control measures. Extensive use has been made of quantification methods such as Fault Tree Analysis and Event Tree Analysis. Physical Effects Modeling has also been applied extensively to estimate the severity and consequences of specific incident scenarios. Much experience has been gained in presenting the results of all this work in a consistent and understandable format, providing interpretations of the results and recommending the most appropriate improvements for the installation of a surface BOP system.

QRA is considered a valuable tool in a decision making process, especially when a surface BOP system is being employed for the first time. It provides a mechanism to communicate among the experts involved, to quantify opinions and to combine these effectively with available statistical data. A properly performed risk analysis documents the best knowledge of the company's technical experts. The application of QRA techniques for SBOP operations has contributed not only to increased safety but also to improved cost effectiveness in many areas.

A HAZOP is a structured hazard identification tool using a multi-disciplined team. It has become accepted as the main technique for the identification of process hazards in the design and operation of new equipment and has been used by several companies intent on installing surface BOP equipment. Other identification techniques such as discipline review or compliance with checklists are limited by their reliance on previous experience and constrained by their narrow approach. HAZOP is based on brainstorming and has important advantages over other techniques for non-standard designs.

One formal definition for a HAZOP would be, "The application of a formal systematic examination of the process and engineering intentions of new or existing equipment packages to assess the potential of mal-operation or malfunction of individual items of that equipment package and the consequent effects on the facility as a whole".

The method is equally applicable to:

- New construction projects
- Major conversion or upgrade projects
- Small rig modifications
- New operating procedures
- Changes to existing operating procedures

The technique has been used successfully several times for the use and installation of surface BOP packages.

In its simplest form the concept is to break the equipment package into small sections and then to identify hazards by examining each section and using a series of parameter and guide word filters to structure the brainstorming process. Once hazards are identified, the risks can be ranked and changes made to equipment configurations or operational procedures to reduce risk. Additional mitigation strategies can be introduced to mitigate the consequences of remaining risks.

4.2.2 Hazard Identification Guidelines (HAZID)

HAZID (HAZard IDentification) is a technique for early identification of potential hazards and threats. The technique has two styles, **Conceptual** and **Detailed** both techniques are recommended when a surface BOP operation is planned for a rig application that has never used surface BOP's before. It is likely to be the first formal HSE-related study for a surface BOP project. The major benefit of the HAZID exercise is that it can quickly identify and assess the critical HSE hazards and therefore provide essential data for the key project decisions. This has lead to safer and more cost-effective design options being adopted with a minimum cost of change penalty.

The HAZID technique is a:

- Means of identifying and describing occupational HSE hazards and threats at the earliest practicable stage of the surface BOP Project
- Meeting or workshop session employing a highly experienced multi-discipline team using a structured brainstorming technique, based on a checklist of potential HSE issues, to assess the applicability of potential hazards
- Rapid identification and description process only, not a forum for trying to solve potential problems

4.2.2.1 HAZID Benefits

HAZID has been developed specifically to reflect the importance of HSE issues on the fundamental (and often non-HSE-related) decisions that are made at the inception of surface BOP projects. The HAZID is usually the first opportunity to collect experienced line and HSE staff together to address, in a short timeframe, the issues surrounding fabrication, development and installation issues associated with a SBOP project.

The benefits of using HAZID include:

- Full recognition of the importance and interdependence of all HSE aspects at the outset of the SBOP project
- Provides an opportunity to consider the HSE implications of alternative equipment packages and process designs as part of the selection between (competing) options. (i.e., suspend the surface BOP from above or below, how many rams in the disconnect device, do we need a disconnect device, etc)
- The potential to affect major changes to philosophy/design at a very early stage before significant financial commitments are made
- Identification of specific hazards and threats within a project life
- The Hazid exercise provides a process to record HSE hazards and threats which can then be used

to develop a rig specific HSE Hazards and Effects Register. Documenting all potential Hazards in the preparation phase of a surface BOP project is imperative.

4.2.2.2 HAZID Timing and Duration

The major benefits from HAZID arise from the technique being used at the earliest possible stage of a surface BOP program. The constraints on the timing of any study arise from establishing a balance between having enough information available to the team and still having the ability to change or affect the basic equipment decisions. In any event the study should be held as soon as enough general information is available.

For a **Conceptual HAZID** this would include information on the proposed equipment configurations, riser size, seabed isolation device (SID), control systems options, mooring or DP options, metocean data, well subsurface data etc. For a **Detailed HAZID** design work would normally have progressed to the point where the rig has been selected, the equipment vendor / manufacturer is known, all major subsurface data is know, and all metocean data understood and initial riser analysis work has been completed. In all other aspects there is no difference between the two styles of study. All paragraphs in this document apply to both Conceptual and Detailed HAZID studies.

The objective of a HAZID study is to recognize and identify the issues rather than to discuss the consequences and propose solutions. Hence the duration of a HAZID study is normally short, (a typical study duration for a surface BOP project is one to two days).

4.2.2.3 HAZID Participants

A HAZID team should be kept comparatively small but the team should contain sufficient knowledge to recognize and identify all the HSE issues associated with the surface BOP project. Typical teams from previous exercises involving surface BOP's have included anywhere from 10 to 20 members. It is recommended that the following key members of the team should be included:

- Senior Well Engineering representatives
- Drilling Superintendent representative
- Rig Manager or equivalent
- Representative from the Regulating Authority
- Rig Engineering Department representatives
- HSE Advisers from both the Oil Company and Rig Owners organizations
- Surface BOP Equipment Manufacturer representatives
- Subsurface representatives or Pressure Prediction representatives
- ROV Company representative

4.2.2.4 Performing a HAZID

The HAZID process as previously mentioned is a method to quickly and efficiently focus attention and talents of a group of individuals (team) to identify and assess hazards associated with a particular system, or surface BOP package. The exercise is typically not a forum for solving issues or suggesting re-design options, however depending on the development stage of the system or concept, useful mitigation options may be suggested and captured during the exercise.

Figure 4.2.2.4 (known as the "Bowtie Diagram") logically depicts how each hazard can evolve into an undesirable "top" event, and ultimately into an undesirable consequence. The HAZID exercise focuses primarily on the left-hand side of the diagram, identification of top events, identification of the threats that could lead to these events, and assessment of the effectiveness of safeguards and barriers. However, potential consequences can also be assessed during the exercise allowing the hazardous event to be risk ranked by the team.

The top event that is typically reviewed in surface BOP operations is a blow out. Several previous studies on surface BOP systems have indicated / concluded that a blow out presents the most severe threat to human life and the environment. In previous studies nine primary threats have been identified that have the potential of leading to this top event.

4.2.2.5 Organization and Data Capture

A surface BOP HAZID can be organized around nine primary threats. Each threat generally represents a failure of a component in the system. Organizing the HAZID in this manner helps the team focus on the particular threats associated with specific systems in the surface BOP or support structure. These nine primary threats covered during the HAZID include:

- Failure of the BOP to isolate a kick
- Failure of the choke and kill (C/K) line to retain pressure integrity
- Dropped object damages choke and kill lines in the moonpool
- Loss of position leading to riser failure
- Riser failure (catastrophic) due to fatigue, wear, overstress, overpressure, collapse, etc.
- Collision
- Loss of riser support
- Failure of the SID
- Fracture of the shoe

For each primary threat, specific deviations or sub-component failures should be identified. In order to expedite the process all of the potential threats should be preloaded into worksheets this then allows the team to brainstorm barriers that are in place as well as potential consequences. It may be the case that additional threats will be suggested during the workshop and added to the worksheet. In addition to discussion around potential threats, the HAZID process should also capture the following.

- Barriers or Preventive Measures
- Consequences
- Risk Ranking (People, Assets, Environment and Reputation)
- Comments (Remarks and Mitigation Suggestions)

The hazards, barriers and consequences captured in the worksheets relate to the perceived threat and provide the basis of a risk ranking exercise.

4.2.2.6 Risk Ranking

A typical risk ranking matrix should be used by the HAZID team, an example matrix is shown in Figure 4.2.2.6a. Consequence definitions should also be agreed and made use of in the HAZID exercise. An example of this is shown in Table 4.1.2.6b. Each identified threat should be evaluated;

a) with respect to the severity of anticipated consequences and
b) with respect to the anticipated frequency of the threat occurring

Risk ranking should be based on the following definitions:

Consequence - the maximum CREDIBLE effect without safeguards in place

Frequency - best estimate of how often the maximum credible effects may occur assuming the safeguards ARE in place

Threats of low frequency and low consequence are generally judged to be acceptable, but should be carefully managed to ensure continuous improvement. Threats having a relatively high frequency or consequence require incorporation of reasonable risk reduction measures to preclude occurrence. For threats with a high frequency and consequence, the risk is intolerable – operation in this region will not be permitted and mitigating action must be taken at the design stage to reduce risk to tolerable regions.

The final result of the exercise is that a report should be compiled and shared with all involved in the surface BOP project. This report will form the basis of several follow on exercises, the actions identified or work programs identified from the exercise should also be captured in a live work log until the project with surface BOP's is complete.

4.2.3 Quantitative Risk Assessment Guidelines.

Once hazards and hazardous events have been identified, their causes, consequences and probability can be estimated and the risk determined. Risk assessment may be on a qualitative or quantitative basis. Both involve the same steps. Qualitative methods may be adequate for risk assessments of simple facilities or operations where the exposure of the workforce, public, environment or the asset is low. However, the application of quantitative methods is considered to be desirable when making use of surface BOP Equipment for the first time. The QRA technique can be used quickly and cheaply to help structure the solution to problems for which the solution is not intuitively obvious.

Risk is often defined as a function of the chance that a specified undesired event will occur and the severity of the consequences of the event. When risk is assessed qualitatively a Risk Matrix may be used. When assessed quantitatively, risk is derived from the product of chance and potential consequence. For QRA purposes, chance is usually expressed as the frequency of occurrence. If no attempt is made to estimate the frequency, we may be driven by the consequence into investing heavily on risk reduction measures which are ineffective. Refer to Figure 4.2.3.

Many are concerned about the accuracy of the quantification and use this as a reason why the technique should not be applied. However, whether we realize it or not, we are always making implicit comparative quantification whenever we make a decision. What we gain with QRA is a structured assessment of the risk instead of an intuitive type of quantification. The numbers used in a QRA may be very approximate, but at least we have broken down the problem into its basic elements and made an objective judgment for each of these elements rather than an overall judgment on a largely subjective basis. However, when there are a large number of situations to be analyzed, it may be advantageous to precede the QRA study by a consequence analysis. This may filter out the cases where a full QRA would not add additional information.

There are several situations in which QRA has and is being misused. This misuse is not necessarily deliberate but can arise from a misunderstanding of the QRA process.

4.2.3.1 QRA Objectives

The objectives of previous QRA studies for SBOP operations have been to:

- Compare the frequency of hydrocarbon release for both surface and subsea BOP operations,

- Evaluate the risk of fatalities occurring as a result of release of hydrocarbons,
- Characterize the frequency and duration of resulting hydrocarbon release, and
- Evaluate the sensitivity of the release estimates to certain key parameters.

4.2.3.2 Methodology

The approach adopted in typical studies involves:

- Identification of hazards introduced, changed, or removed with the introduction of surface BOP drilling operations
- Identification of region or application specific characteristics that may have an impact on the analysis
- Estimation and comparison of risks associated with surface BOP drilling and conventional subsea BOP drilling using accepted quantitative risk assessment techniques

4.2.3.3 Identification of Hazards

The HAZID process can perhaps best be described as a method for quickly and efficiently focusing the attention and talents of a group of individuals in order to identify and assess hazards associated with a particular system, component, or design. For best results, the group chosen for the exercise should represent a variety of disciplines, such as engineering, operations, etc., but should be limited in number to ensure that the HAZID proceeds in an orderly fashion with active participation of those in attendance. The exercise employs the "brainstorming" technique to rapidly identify and assess potential hazards, but is not a forum for solving the issues identified.

The findings of a surface BOP HAZID exercise will be specific to the configuration being considered. The findings of a typical HAZID exercise are indicated below. In this case it the configuration was an SBOP system deployed from a DP rig using a SID device with acoustic control.

- There were no hazards identified during the study that might prevent eventual deployment in the field. However, there are a number of issues that will need to be addressed prior to deployment. In particular, the SID acoustic control system must be addressed in detail to ensure the system provides a reliable means to shut-off and disconnect from the well.

- Most of the hazards identified during the HAZID were judged as issues that would be addressed during the design as well as development of surface BOP operating training and procedures. Note that operator training and development of detailed procedures specific to the surface BOP operation was perceived as being very important for safe operations and is one of the suggested recommendations from this HAZID

- Events related to operations from the DP drilling vessel (i.e., loss of position leading to riser failure) had risk rankings comparable to other threats identified in the HAZID. Use of the SID was seen as a critical component to ensure safe disconnects in the event the DP vessel lost position.

4.2.3.4 Identification of Regional or Application Specific Characteristics

The QRA study employs the techniques of fault tree / event tree analysis to determine the frequency and consequences of blowout for subsea BOP and surface BOP configurations to allow a direct comparison of the risks associated with each. The study may use relevant previous fault tree studies as a starting point, the fault trees are developed and reviewed by the QRA team. The information captured during the HAZID exercise is also reviewed.

Revisions to the fault tree structure are conducted to ensure that all identified characteristics of the area of operation were properly modeled. Examples of particular enhancements made to the model in typical SBOP studies are in the area of weather response of site specific metocean data, Vortex Induced Vibration (VIV) for site specific current data, Drillstring Induced Vibration (DIV) for a particular drill string/riser combination, use of Dynamic Positioning (DP) rather than a moored rig if applicable, and inclusion of an SID or other specific equipment in the system configuration.

In the area of region specific data collection, some items such as BOP component failure probabilities, DP or mooring system failure probabilities for example may have to be developed based on data collected in other regions and adapted for the site under consideration. Any differences in regional specific conditions should be taken into account when using data developed in other areas.

4.2.4 Major Hazards Associated With Surface BOP Operations

The general conclusion of the various hazard identification/assessment studies that have been conducted for surface BOP operations has been that the difference in risk between conventional subsea BOP operations and surface BOP operations manifests itself through the hydrocarbon release event. All other potential major accident events typically considered for a semisubmersible drilling rig (i.e. non-well related fire/explosion, major mechanical failure, helicopter crash, loss of stability, etc.) were deemed to be unaffected.

The accident scenarios typically affected by the introduction of surface BOP operations, are illustrated in Figure 4.2.4. The events depicted in this figure provided the roadmap for the fault trees and events trees developed for the analysis.

4.2.4.1 Determination of Hydrocarbon Release Frequency

The fault tree structure should be determined by logically grouping failure scenarios with similar outcomes (location and duration of the release), as well as likely recovery actions available. The models for the surface and subsea BOPs should be constructed as a single set of fault trees that can be used to evaluate the configurations simply by altering the basic event data supporting the fault tree.

An example of the relationship of the fault trees to the final consequence analysis is shown in Figure 4.2.5.1.

The key elements of each fault tree and the differences between the surface and subsea cases are typically:

- Failure of BOP to close in order to properly respond to a kick
- Delay in kick detection, allowing gas above the BOP before closure
- Failure of the riser

- Loss of well integrity at or below the wellhead

Each of these is discussed in the following sections.

4.2.4.2 Failure of BOP to Properly Respond to Kick

Failure of the BOP to properly respond to a kick is primarily a function of the reliability and quantity of annulars, pipe rams, shear rams, and control systems. In addition, human error can have a significant impact on BOP reliability. Hydrocarbons are assumed to be released at the drill floor in the event that the BOP fails to properly respond to a kick. Failures related to choke and kill lines are also included in this fault tree.

The principal differences between surface and subsea BOP configurations with respect to this hydrocarbon release scenario are the number of annulars/rams and the control system configuration. A subsea BOP typically has two annulars, three pipe/variable rams, one blind shear ram, and two control pods, while a typical surface BOP has one annular, two pipe/variable rams, one blind shear ram, and one control pod.

Both designs have advantages. For instance, the increased redundancy of the subsea BOP increases its reliability, and location of the BOP on the seabed results in a significant distance between the point of well isolation and the rig floor. However, balanced against this is the fact that the surface BOP is accessible in the moonpool, improving access for maintenance and inspection with the effect of increasing the reliability of the system. The control panel of the surface BOP is also simplified, lessening the potential for human error during BOP operation.

For the surface BOP case, failure of the BOP does not necessarily lead to continued blowout. Successful closure of the SID (if deployed) is assumed to lessen the consequence, resulting in a release of limited duration equivalent to the delayed BOP closure case described in the following section. This is accomplished by adding a SID closure event in the consequence event trees, with the reliability of SID closure determined simply by quantifying the appropriate fault tree used elsewhere in the model.

4.2.4.3 Delay in BOP Closure

Delay in detection results in a hydrocarbon release (of very limited duration) because the kick passes the BOP before it can be closed, resulting in a release of finite volume at the drill floor. The principal inputs to this section of the fault tree are failure of the detection equipment on the drill floor and mud loggers cabin, human error in kick detection, diverter failure, and failure to close the diverter in time.

The significant differences between surface and subsea BOP operations arise as the result of the fact that a kick rapidly increases in size as it expands to the surface. A kick small enough to be missed at the seabed becomes so large as it continues up the riser that the probability of failure to detect is minimal in the surface BOP case. This effect is more pronounced as water depth increases.

4.2.4.4 Riser Failure

Failure of the riser results in the release of hydrocarbons somewhere between the seabed and the rig. The principal causes that should be modeled in the fault tree include:

- Vortex Induced Vibration (VIV)
- Drillstring Induced Vibration (DIV)
- Wear or material defects leading to failure below the design rupture and collapse ratings
- Impact due to ship collision or dropped object
- Riser support system failure
- Extreme weather leading to loss of position
- Loss of position within normal weather criteria

The major difference between the surface and subsea BOP cases results from the placement of the BOP stack. In the event of a total riser failure (with drillstring integrity compromised), the subsea BOP and the SID are somewhat comparable, as the only usable preventer in the subsea BOP is the blind shear ram.

4.2.4.5 Seabed Blowout

Seabed blowout can occur as the result of two principal causes, loss of the casing shoe during kick killing operations or mechanical failure of the casing below the BOP at the seabed (coupled with either a kick or when drilling in the reservoir with no riser margin). The principal causes for loss of casing shoe are considered to be human error in drilling beyond the kick tolerance determined by the leak off test and human error during well control.

The frequency of underground blowout for the subsea BOP case in deep water is higher than the equivalent surface BOP case principally because well control is more difficult in deeper water due to higher choke line frictions.

4.2.5 Summary of Predicted Hydrocarbon Release Frequencies

4.2.5.1 Fatality Risk Analysis

The fatality risk due to hydrocarbon release is calculated using event trees with the structure illustrated on Figure 4.2.5.1. This structure is based on the fatality analysis event trees used in the QRA produced in support of previous SBOP studies.

4.2.5.2 Environmental Risk Analysis

The ultimate consequences of a release of hydrocarbons to the environment are extremely difficult to estimate due to the complex issues surrounding such a release. Impact is dependent upon the well location in relation to environmentally sensitive areas and the nature of the reservoir. In addition to immediate recovery and cleanup costs, long term impact to both the local area and to company / industry reputation can vary widely based on the individual circumstances surround the release.

4.2.5.3 Sensitivity Analysis

When performing a quantitative analysis, it is often useful to examine the behavior of the results in response to changes in certain key parameters. By performing such sensitivity analysis, conclusions can be drawn regarding the general applicability of the results even in cases where sparse data exists to support the estimate used for a given parameter. In addition, sensitivity analysis allows for the impact of proposed configuration changes to be evaluated.

4.2.6 Hazard and Operability (HAZOP) Exercise

The HAZOP technique uses a multi-disciplined team of experts working in a systematic brainstorming process, for the purpose of examining the potential for incorrect or improper operation or malfunction of equipment and the consequential effects on the system. The classical HAZOP process is a systematic application of combinations of parameters (flow, temperature, pressure) and guidewords (no, more, less, etc.) to produce deviations from the design intent or intended operation. Credible causes of the deviation are identified, existing barriers and consequences are assessed, and additional actions or requests for further consideration are documented by the team. For HAZOPs that evaluate activity-driven processes, or those that include the impact of procedures, the base guidewords take on slightly different meaning from the standard application. Additional guidewords may also be required to address the concepts of timing, position, etc. The parameters and guidewords used in a typical SBOP HAZOP study are shown in Table 4.2.6.

To enhance the HAZOP, simple "What If?" type hazard identification was also allowed. The What-If method uses broad, loosely structured questioning to postulate potential mishaps and ensure that appropriate safeguards are in place. "What-If" analysis can be used for practically any system or activity, and generates qualitative descriptions of potential problems (in the form of questions and responses) as well as lists of recommendations for preventing problems. By combining the highly structured HAZOP guideword/parameter approach with the loosely structured "What-If" method, the best features of both can be incorporated.

4.2.6.1 HAZOP Organization

The HAZOP exercise may be organized around a number of distinct operational activities or "nodes." Dividing the HAZOP into nodes allows the team to focus on the particular hazards associated with each required activity. Some key phases of the surface BOP drilling operation are briefly summarized below. The details of these will be specific to the configuration being studied.

- Preparations/testing of the surface BOP, SID, and control system on deck
- Deployment of the SID and casing riser, including umbilical and strakes if applicable
- Space-out and installation of the surface BOP and telescoping joint, latching of the SID
- Pressure testing of the system on the wellhead
- Operation of the system during drilling operations
- Retrieval of the telescoping joint and surface BOP
- Retrieval of the casing riser and SID

Potential hazards for each node may be identified and defined using the HAZOP technique described in the previous section. Prior to the workshop, the deviation table is developed specifically for the particular surface BOP system configuration and its deployment, operation, and retrieval.

Figure 4.2.6.1 shows a diagram of the general process used during the workshop. During the process, the following information was captured from the team's discussions:

- Hazardous Event / Threats
- Barriers or Preventive Measures
- Consequences
- Risk Ranking
- Additional Mitigation Measures
- Comments

The hazards, barriers and consequences captured in the worksheets relate to the perceived threat and provide the basis of the risk ranking. The hazard event is then risk ranked using the process and risk matrix described in 4.2.2.6.

4.2.6.2 Hazard Identification

Typical hazards identified for surface BOP operations fall into the following categories. The hazards are system specific and may be different for different equipment configurations.

- Dropped objects

  In general the dropped objects relate to three areas e.g. heavy non-standard lifts of the SBOP or SID, dropped objects affecting personnel in the moonpool, and dropped riser/SID.

- Procedural issues

  Procedural issues generally relate to hazards associated with critical steps to which particular attention must be paid to the preparation and execution of the procedure and practical considerations to maximize the efficiency of the operation.

- Equipment issues

  Equipment damage issues can be addressed by enhancements to procedures and/or equipment configuration and setup.

- High pressure hazards

  High pressure hazards relate to the obvious hazards associated with pressurized systems and additional hazards around the potential for trapped pressures as the SID, controls or other components are brought to surface.

- Materials compatibility

  Materials issues related to the use of high strength casing riser and the potential for adverse circumstances caused by cathodic protection systems.

4.2.6.3 Hazard Mitigation

Hazards identified and ranked that have a risk that is unacceptable or can be improved are mitigated by changes in equipment configuration or operational procedures depending on the circumstances. A typical surface BOP HAZOP may generate numerous mitigation strategies depending on the equipment configuration.

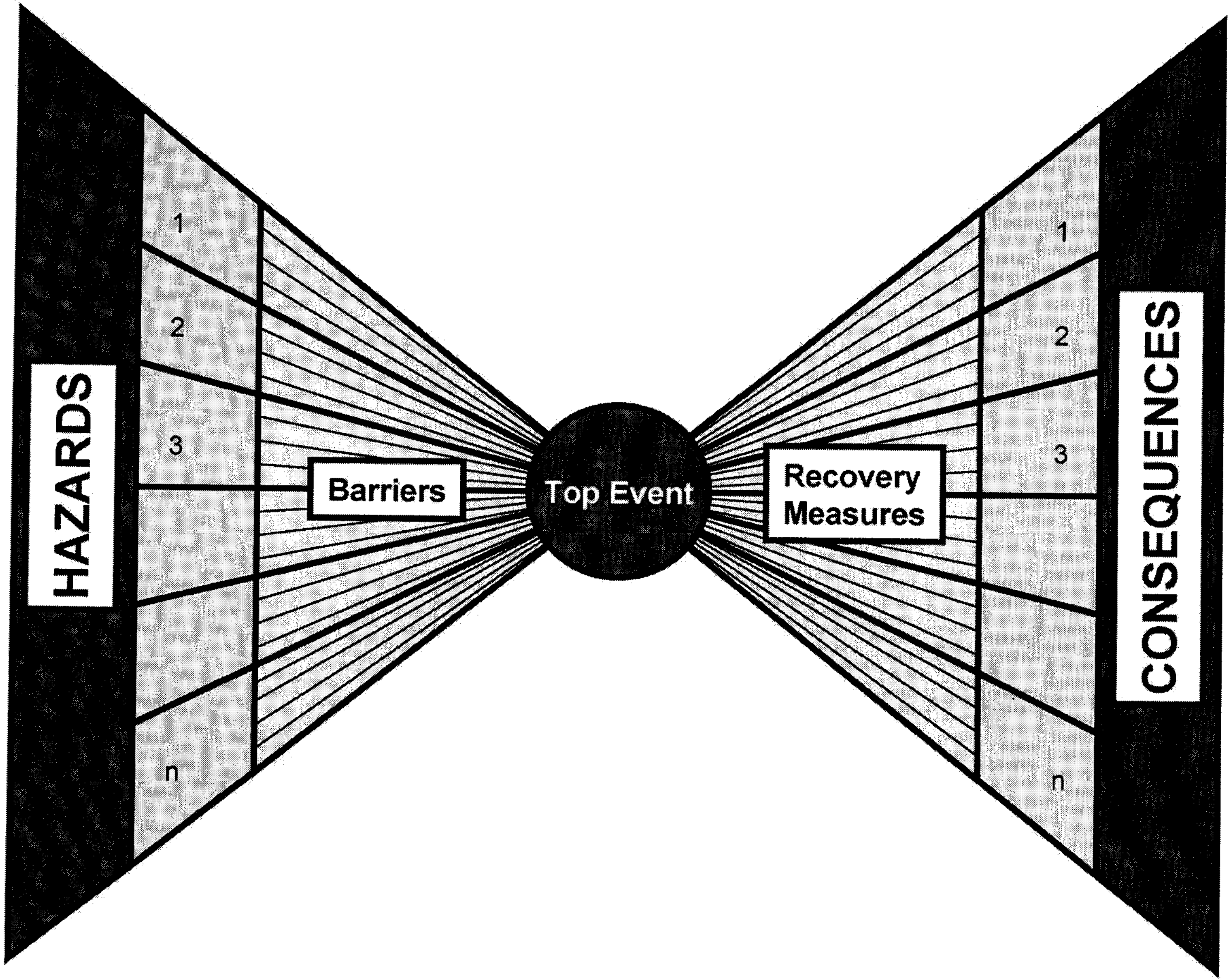
HAZARDS
1
2
3
n
Barriers
Top Event
Recovery Measures
1
2
3
n
CONSEQUENCES

Figure 4.2.2.4

		Consequence				Probability (Increasing →)				
						A	B	C	D	E
Increasing ↓		People	Assets	Environment	Reputation	Never heard of in (EP) industry	Heard of in (EP) industry	Incident has occurred in our company	Happens several times per year in our company	Happens several times per year at location
	0	No injury or damage to health	No damage	No Damage	No impact	3	3	3	3	3
	1	Slight injury or health effects	Slight damage	Slight damage	Slight impact	3	3	3	3	
	2	Minor injury or health effects	Minor damage	Minor impact	Limited impact	3	3	3	2	2
	3	Major injury or health effects	Local damage	Localized impact	Considerable impact	3	3	2	2	
	4	Single fatality or permanent total disability	Major damage	Major impact	Major national	2	2	2		
	5	Multiple fatalities	Extensive damage	Massive impact	Major international	2	2			

Figure 4.2.2.6a

Severity	People				Assets	
	Injury		Health			
	Potential Impact	Definition	Potential Impact	Definition	Potential Impact	Definition
0	No injury	No injury or damage to health	No Injury	No injury or damage to health	No Damage	No damage to equipment
1	Slight injury	Not detrimental to individual employability or to the performance of present work	Slight injury	Not affecting work performance or casing disability. Agents which are not hazardous to health.	Slight damage	No disruption to the process, minimum cost of repair (below $10,000)
2	Minor injury	Detrimental to the performance of present work, such as curtailment of activities or some calendar days to recover fully, maximum one week	Minor injury/illness	Affecting work performance, such as restriction to activities (Restricted Work Case) or a need to take a few calendar days to recover fully. Agents which have limited health effects which are reversible, e.g. irritants, many food poisoning bacteria	Minor damage	Possible brief disruption of the process; isolation of equipment for repair (estimated cost below $100,000)
3	Major injury	Leading to permanent partial disablement or unfitness for work over extended period, such as long term absence	Major injury/illness	Resulting in permanent partial disability or affecting work performance in the longer term, such as a prolonged absence from work. Agents which are capable of irreversible damage without serious disability, e.g. noise, poorly designed manual handling tasks.	Localized damage	Plant partly down; process can (possibly) be restarted (estimated cost of repair below $1,000,000).
4	Single fatality	Alternatively victim with permanent total disablement or unfitness for work. Also includes the possibility of multiple fatalities (maximum 3) in close succession due to the incident, e.g. explosion	Permanent total disability or fatality (small exposed population)	Agents which are capable of irreversible damage with serious disability or death, e.g. corrosives, known human carcinogens.	Major damage	Partial loss of plant; plant shut down (for at most two weeks and/or estimated repair costs below $10,000,000.
5	Multiple fatalities	May include four fatalities in close succession due to the incident, or multiple fatalities (four or more) each at different points and/or with different activities	Multiple fatalities	Agents with potential to cause multiple fatalities, e.g. chemicals with acute toxic effects (e.g. hydrogen sulphide, carbon monoxide), known human carcinogens	Extensive damage	Total loss of the plant; extensive damage (estimated cost of repair exceeds ($10,000,000)

Figure 4.2.2.6b

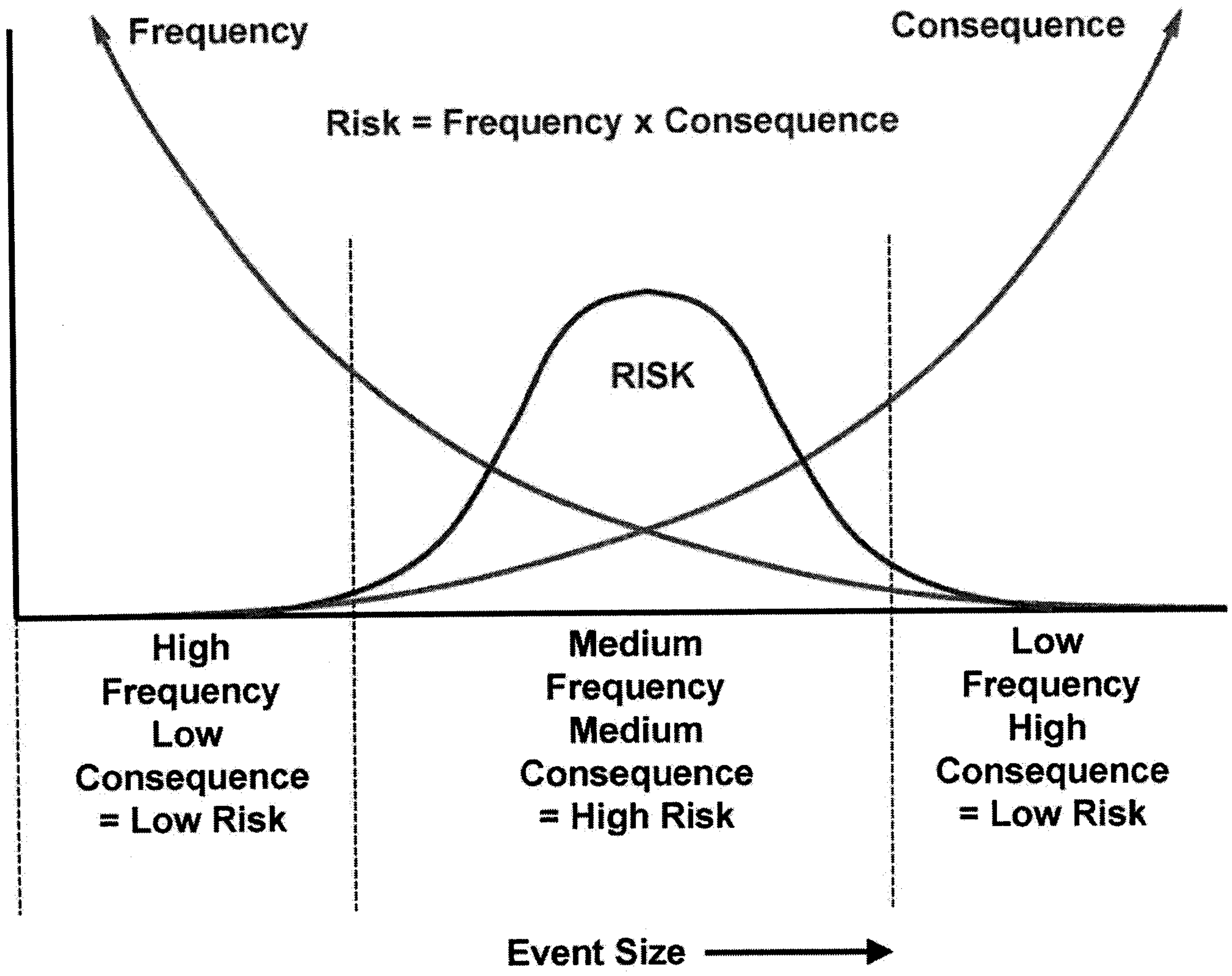
Frequency
Consequence
Risk = Frequency x Consequence
RISK
High Frequency Low Consequence = Low Risk
Medium Frequency Medium Consequence = High Risk
Low Frequency High Consequence = Low Risk
Event Size

Figure 4.2.3

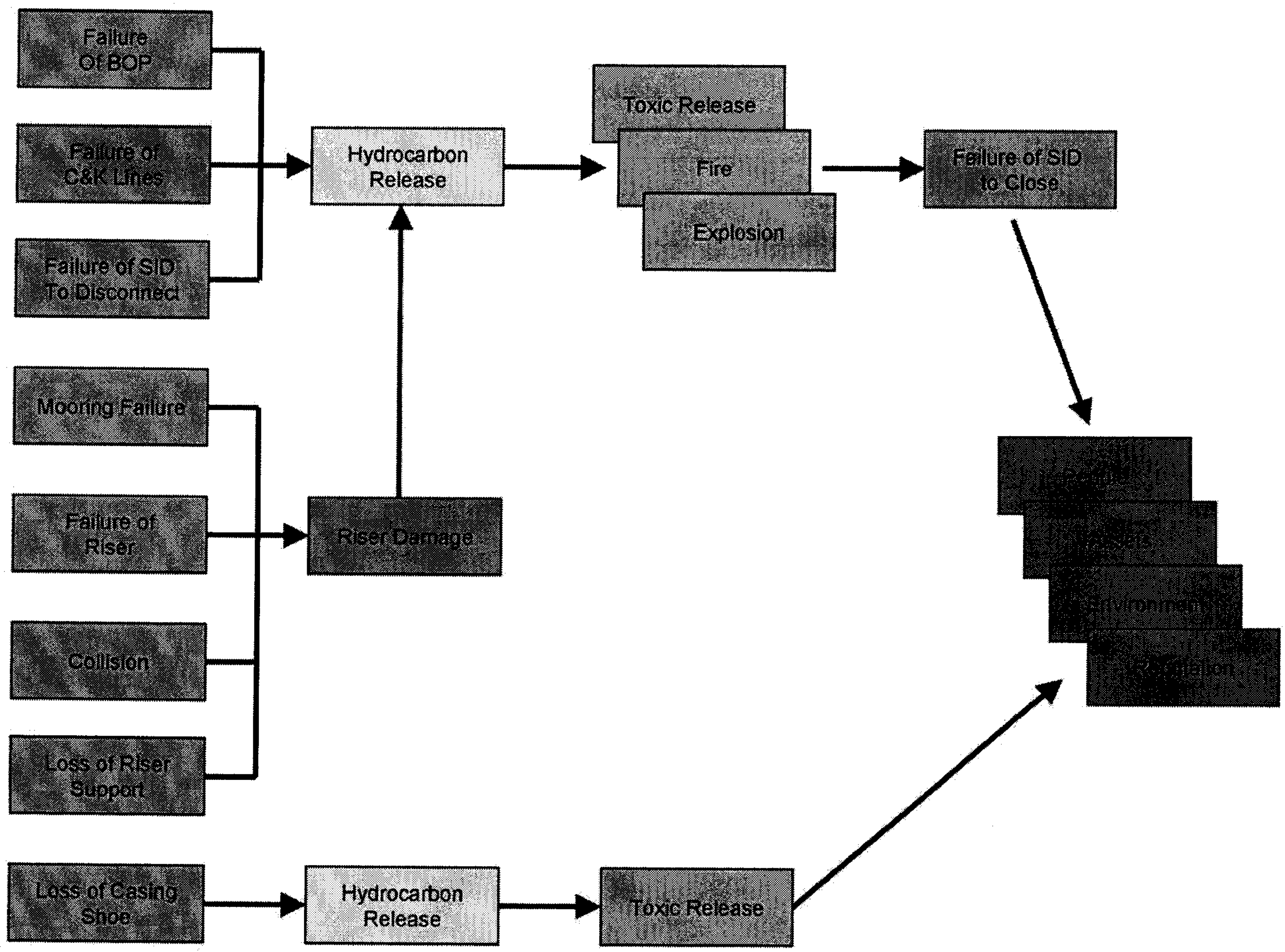
Failure
Of BOP
Failure of
C&K Lines
Failure of SID
To Disconnect
Mooring Failure
Failure of
Riser
Collision
Loss of Riser
Support
Loss of Casing
Shoe
Hydrocarbon
Release
Riser Damage
Hydrocarbon
Release
Toxic Release
Fire
Explosion
Failure of SID
to Close
Toxic Release

Figure 4.2.4

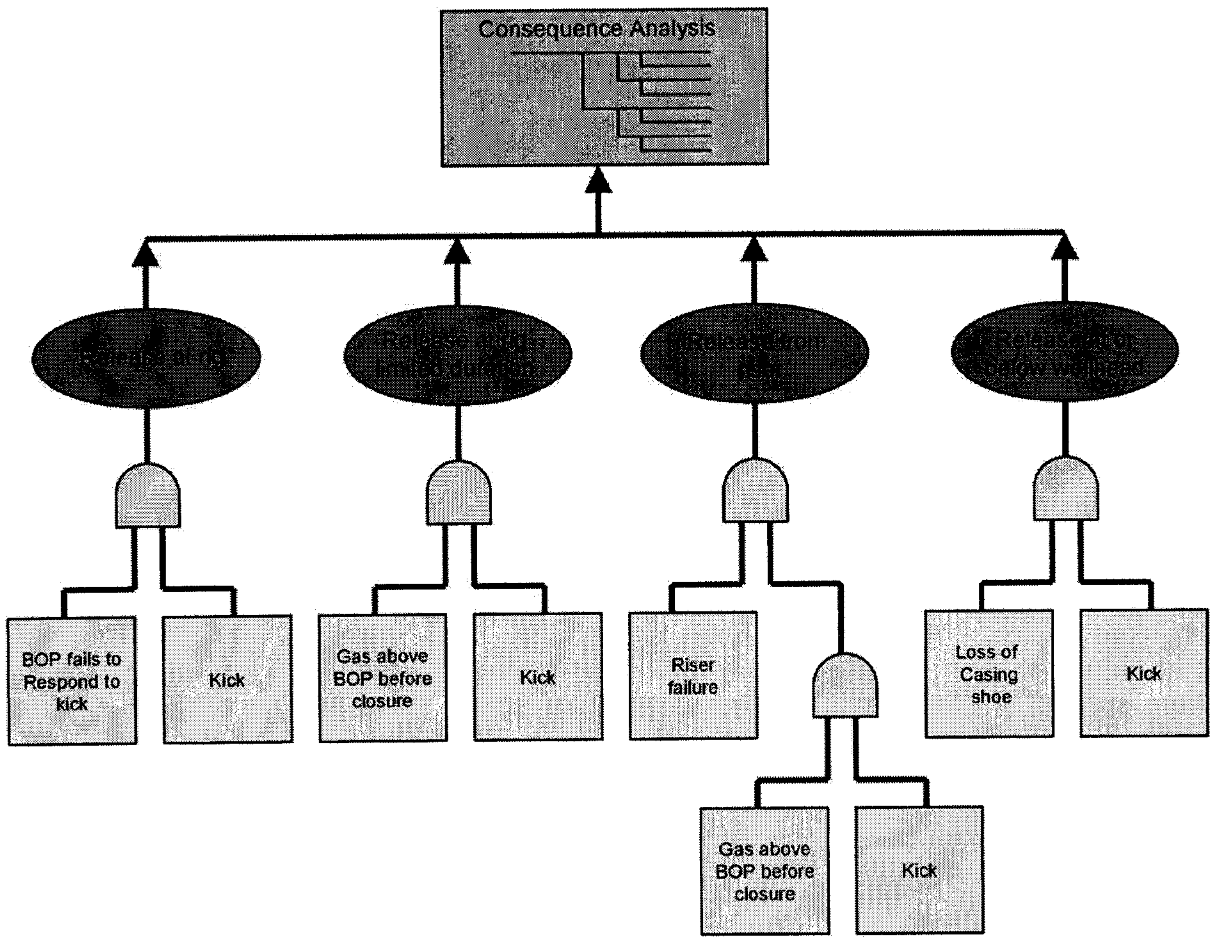
Consequence Analysis
BOP fails to Respond to kick
Kick
Gas above BOP before closure
Kick
Riser failure
Gas above BOP before closure
Kick
Loss of Casing shoe
Kick

Figure 4.2.5.1

Guidewords

Parameter	No Not None	Less Low Short	More High Long	As Well As Also	Part Of	Reverse	Un-anticipated	Other than	When Where Who
Time Procedure	Skipped or Missing step	Too short Too little	Too long Too much	Extra Actions(s) (Shortcuts)	Action (s) Skipped	Out of Order Opposite	Unexpected Condition	Wrong Action (s)	Misc
Equipment	Equipment Unavailable	Interference Blockage		Too much Equipment (Congestion)	Too little Equipment (Supply)	Spurious Operation	Equipment Failure	Wrong Equipment	Misc
Speed	Stopped	Too slow	Too fast		Out of Sync	Backward	Unexpected Speed	Misc	Misc
Flow	No Flow	Low rate Low total	High rate High total	Impurities		Backward	Unexpected Flow	Wrong Material	Misc
Pressure		Low Pressure	High Pressure			Vacuum	Unexpected Pressure	Misc	Misc
Temp		Low Temp	High Temp				Unexpected Temperature	Misc	Misc
Level	Empty	Low Level	High Level				Unexpected Level	Misc	Misc
Special	Wind Wave Current	External Events	Dropped Objects	Debris Issues	Composition H2S, Co2 Paraffin, Sand	Fire Explosion	System Interface	Communic ation	Misc

Table 4.2.6

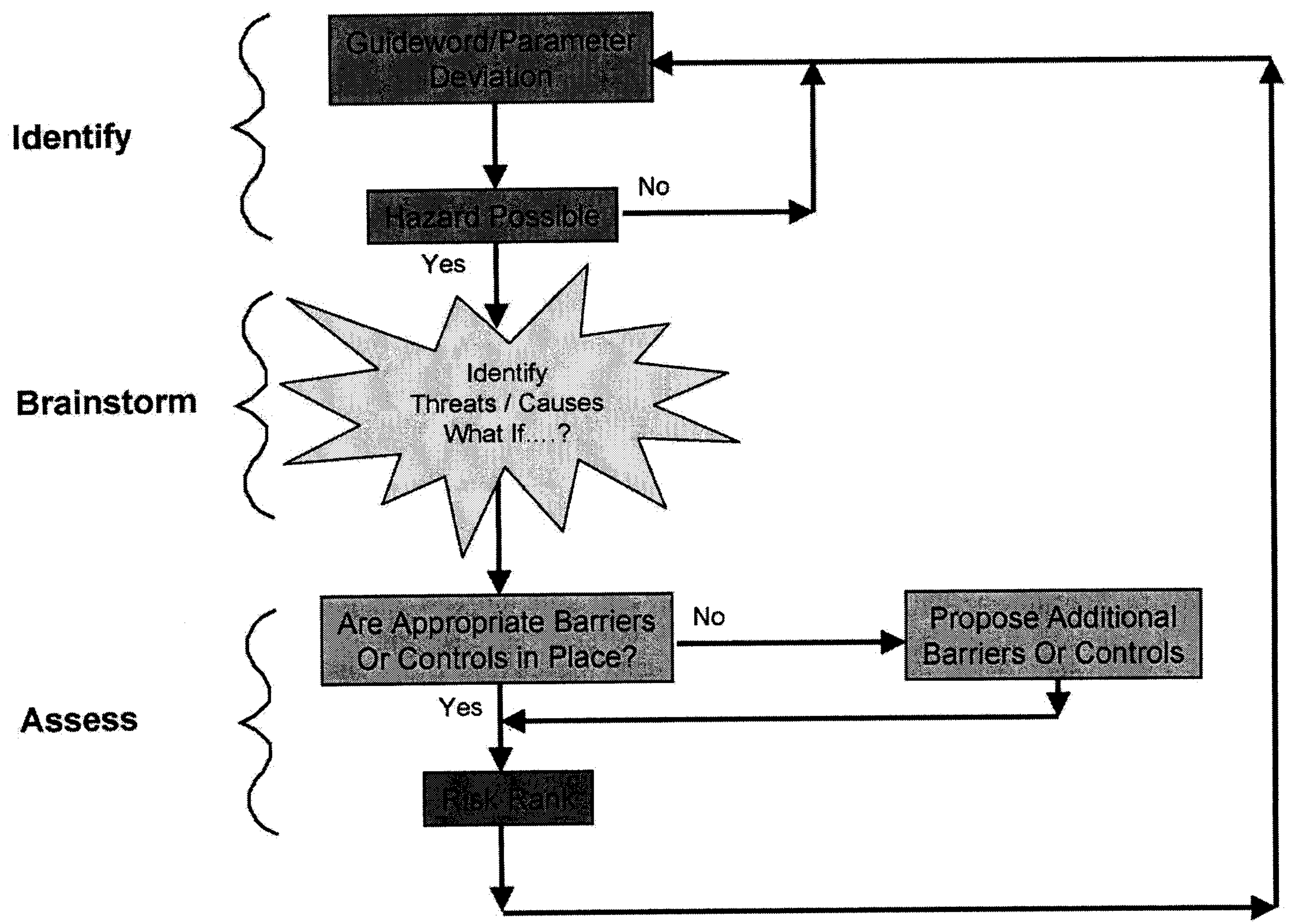
Identify
Guideword/Parameter Deviation
Hazard Possible
No
Yes
Brainstorm
Identify
Threats / Causes
What If.... ?
Assess
Are Appropriate Barriers Or Controls in Place?
No
Propose Additional Barriers Or Controls
Yes
Risk Rank

Figure 4.2.6.1

4.3 Well Control

The following well control guidelines are based on the IADC Deepwater Well Control Guidelines, Chapter 2 - Well Control Procedures, with appropriate modifications for surface BOP operations. Surface BOP operations from floating rigs will in general be conducted in deep water. Surface BOP operations in shallow water (from bottom founded or fixed platforms) are not covered in these guidelines.

4.3.1 Kick Prevention & Detection

4.3.1.1 Kick Warning Signs

The standard well kick warning signs for surface BOP operations are:

- Flow rate increase (delta over 15-30 second averaging measuring device useful)
- Pit volume increase (pit volume totalizer is absolutely necessary)
- Rate of penetration increase
- Decrease in pump pressure
- High gas units
- Sudden torque increase
- Change in mud chlorides

- While tripping, hole not taking the proper amount of fluid
- Well flow with pump shut-down
- Increasing rate of flow on return flow during connections

4.3.1.2 Mud Density

In deepwater, it is not generally possible to drill with enough mud density to keep the well over-balanced upon loss of the riser drilling fluid ("Riser Margin"). This should be considered when configuring the SBOP system particularly the requirement for use of an SID.

Synthetic-based muds (SBM) and oil-based muds (OBM) have different compressibility and thermal expansion properties than water-based fluids. As a result, surface mud density alone may not be an accurate measure of downhole density and hydrostatic pressure. This is compounded by long deepwater risers with their associated low temperatures as well as significant use of synthetic fluids in deepwater. These density differences should be considered in well planning and when changing from one type of fluid to another.

4.3.1.3 Mud Viscosity

While primarily a concern for subsea BOP operations with choke and kill lines, viscosity increase in the riser due to length and low temperature could mask shut-in casing pressure (SICP). This effect is increased with synthetic muds that have high viscosity at low temperature and smaller riser sizes.

With surface BOP, a smaller riser is used and kick detection is generally improved. However, the mud in the smaller riser will cool rapidly. The well may flow during flow checks, but could have no shut-in casing pressure due to the mud viscosity masking effect.

In deeper water, the gel strength can be high, especially with synthetic muds. Slow rotation of the drill pipe can be used to reduce the mud gel strength in the riser when breaking circulation.

4.3.1.4 Drilled Cuttings

The impact of increased annular fluid density (riser cuttings) in creating higher than assumed hydrostatic pressure can lead to fracturing of low strength casing shoes, which can lead to the onset of a kick.

Pressure while drilling (PWD) equipment can be useful to provide downhole pressure monitoring and to assess equivalent circulating density (ECD) loading on the casing shoe. This includes impacts of high viscosity as well as any problems with hole cleaning. A pressure sensor in the SID (if used) can provide much of this information.

4.3.1.5 Lag Time and Temperature Effects

In general, lag time for gas units and cuttings increases in deepwater, reducing the timeliness of this data for abnormal pressure detection purposes. With surface BOP using smaller diameter casing riser and increased annular fluid velocity this adverse effect is reduced.

Due to the small riser diameter and long riser length in deep water, flowline mud temperature is not an effective tool in assessing formation temperature or abnormal pressure due to the cooling effect of a long riser.

Mud logging operations can use an in-line sample heater on the mud prior to measuring gas units. Otherwise, cold mud may give lower gas units. Measurement while drilling (MWD) kick detection methods may be useful due to a reduction in other detection capabilities.

4.3.1.6 Environmental Effects

Pitch, roll, and heave motions (due to weather, crane activity, etc.) can significantly impact pit level and mud return detection methods. Two or more level sensors can be placed in each active pit that is subject to pitch and roll effects and connected to a pit volume totalizer (averaging technology) to reduce this effect. The location of the sensor(s) is also important to minimize effects, i.e., center for single sensor, edges for two sensors, etc.

4.3.2 Shut-in

4.3.2.1 Pre-Kick Preparation

Preparation for a kick includes the following:

Casing shoe

- Measure pressure integrity of casing shoes, i.e., by leak-off/integrity tests
- Post both ppg equivalent and associated surface pressure for the mud weight in use
- Update this pressure periodically and when drill string, mud property, or other changes occur which may affect pressure loss

Slow pump data

- Post slow pump data (for at least two pumps) on drill pipe friction loss
- Take pressures on two gauges reading from separate sources to guard against gauge failure.
- Note the pressure required to break circulation the first time, and record this value for use in kick detection and circulation procedures
- Ensure that cuttings in the hole and riser do not affect slow pump data
- Additional methods can be employed at the time of the kick to update this data, i.e., using subsea pressure sensor on the SID

  Note: Slow pump test rates should represent anticipated kill rates. These may be higher than for conventional subsea BOP operations with choke and kill lines. Circulating rates of 5, 10 and 15 bpm are suggested.

Kill sheet

- Maintain an up-to-date kill sheet designed for surface BOP

Float valve

- Use a float valve to prevent backflow, i.e., when removing the top drive (or kelly) from the drill string
- Use a float valve to guard against backflow through the drillpipe during an emergency disconnect and/or failure of the shear rams to seal

Note: Flow up from the drill pipe can impede the ability to stab a safety valve.

C&K line valve positions and space out

- Show C&K line valve positions on a display indicating which valves are open/closed
- Show the proper space out for the surface BOP rams and annular
- Show the relationship between the surface tool joint location and corresponding tool joint location opposite the SID rams

Mud-gas separator capacity

- Post liquid and gas handling capacity of mud-gas separator
- Compare these to the maximum anticipated gas rates that would result from planned well control procedures and well geometry, i.e., pumping rate, design kick

Designated hang-off ram

If hang-off in the SID is anticipated e.g. for temporary abandonment during a storm:

- Identify designated hang-off ram
- If it is a VBR type, post the hang-off capabilities for the various DP sizes in the hole
- Specify if rams are to be locked after closure (if independent locks)

Note: Hanging-off the drill string in the surface BOP will transfer all the string load to the riser tensioners. Depending on the rig capabilities the riser tensioners may not be able to support all the drill string load. All personnel need to be familiar with the system design capabilities and limitations.

Trip Tank

- Ensure trip tank is properly lined up to receive fluid from the flowline
- Ensure trip tank lines are flushed and clear of solids or debris
- Check and calibrate trip tank pit sensor
- Check function and calibration of trip tank mechanical sensor
- Make a visual for flow check at the trip tank if necessary

Personnel drills

- Perform BOP Drills (pit and trip) regularly including tool joint space out to insure crew competency
- Consider having crews perform "stripping drills" prior to drill out of the casing shoes to ensure crew competency in handling stripping

Note: Stripping through a surface BOP annular or ram preventers will transfer loads to the riser tensioners. All personnel need to be familiar with the system design capabilities and limitations.

4.3.2.2 Hard Shut-in versus Soft Shut-In

There is usually only a small difference in fluid hammer effect with hard and soft shut-in methods (it takes very large kick rates to develop hammer pressure). A soft shut-in tends to increase kick volume, which may result in increased casing shoe pressure. Whatever hammer pressures do occur will be primarily at the BOP and have a minimal effect on the casing shoe, which is the critical point in deepwater well control.

4.3.2.3 Annular Shut-in versus Ram Shut-In

Although rams will shut-in more quickly than annular preventers, there are advantages to using either approach as outlined below:

Annular shut-in

- Eliminates the need to insure tool joint is not near the BOP ram
- Provides a means to effectively shut-in while still allowing for movement of the drill pipe to reduce sticking of the drill string

Note: Movement of the drillstring through a surface BOP annular or ram preventers will transfer loads to the riser *tensioners. All personnel need to be familiar with the system design capabilities and limitations.*

Shut-in and hanging off operation with a ram

- Allows well to be closed in more quickly
- May provide higher pressure rating than annulars
- Eliminates wear on BOP due to vessel heave (if motion compensator is kept below string weight).

Shut-in with an annular, then promptly switch to hang-off on a ram BOP

- Defers ensuring that tool joint is not near the BOP ram until it can be accomplished when execution speed is not critical
- Simplifies space-out procedure
- May provide higher pressure rating than annulars

If drilling near a production zone (or if the well is obviously flowing), it may be desirable to skip the flow check, and proceed immediately to close the BOP and check for pressures.

Note: Hanging-off the drill string in the surface BOP will transfer all the string load to the riser tensioners. Depending on the rig capabilities the riser tensioners may not be able to support all the drill string load. All personnel need to be familiar with the system design capabilities and limitations.

4.3.2.4 Shut-In While Drilling

The following is an example procedure for shut-in while drilling.

1. When a primary warning sign of a kick has been observed, immediately raise the drill string until the bit is off bottom and string is at proper space out. As the SBOP is supported on the tensioners and moving relative to the rig floor, keep the motion compensator open and at mid stroke (as local conditions dictate).
2. Stop the mud pumps and check for flow.
3. Close the selected BOP.
4. While the BOP is closing, open selected C&K line valves. *Note: the choke line should now be lined up to the pre-selected choke.*
5. Check for surface leaks. Alert the supervisor.
6. Read and record shut-in drillpipe (SIDPP), shut-in casing pressure (SICP), and pit gain. Monitor and record this data periodically.
7. As the BOP is moving relative to the rig floor avoid landing the pipe in the slips with the SBOP closed unless a proper stripping procedure has been established. If subsequently, drill pipe is hung-off on the slips, be alert for potential fatigue damage from vessel pitch and roll.

4.3.2.5 Shut-In While Tripping

Many top drive systems incorporate one or more full opening safety valves (FOSV) that remain in service during drilling or tripping. These provide a backup in case the rig floor FOSV cannot be stabbed. Assure that a strippable FOSV is provided, sized for the casing in the well. The following table contains an example procedure for shut-in while tripping.

1. When a primary warning sign of a kick has been observed immediately stop all operations and set the pipe in the slips.
2. Install and close the FOSV. *Note: The FOSV and IBOP (with crossovers as necessary) should be in the open position. Check at the start of each tour.*
3. Pick-up the drill string and remove slips. Position drill pipe for proper space out. Open the motion compensator and position at mid stroke. Check for flow.
4. While the BOP is closing, open choke line valves. *Note: The choke flowline should now be open through to the closed pre-selected choke.*
6. Check for surface leaks. Alert the supervisor.
7. Read and record shut-in drillpipe (SIDPP), shut-in casing pressure (SICP), and pit gain. Monitor and record this data periodically.
8. As the BOP is moving relative to the rig floor avoid landing the pipe in the slips with the SBOP closed unless a proper stripping procedure has been

established. If subsequently, the drill pipe is hung-off on the slips, be alert for potential fatigue damage from vessel pitch and roll.

9. Prepare to strip back to bottom with the annular BOP.

Note: Stripping of the drillstring through a surface BOP annular preventer will transfer loads to the riser tensioners. All personnel need to be familiar with the system design capabilities and limitations.

4.3.2.6 Shut-In during a Connection

Ensure that the well is stable before making the connection. If flow is detected after making the connection, the following conditions may occur:

- It may not be possible to slack off and hang on the rams
- It may not be possible to pick up enough to clear the tool joint.

This situation should be treated the same way as a shut-in while drilling. Hang-off depends on rig specific considerations.

4.3.2.7 Shut-In with Bit out of the hole

If kick indicators occur while out of the hole, the first action should be to shut-in with the blind/shear rams. The following is an example procedure for shut-in with the bit above the SBOP.

1. At the first indication of flow from the well, close the blind/shear rams.
2. While the BOP is closing, open the choke line valves. *Note: choke line should now be aligned with the pre-selected choke.*
3. Check for surface leaks. Alert the supervisor.
4. Record shut-casing pressure (SICP), and pit gain. Monitor and record this data periodically.
5. Prepare for stripping and bullheading operations. Implement volumetric pressure control if necessary.

4.3.2.8 Shut-In while Running Casing/Liner

While running casing or liner, the location of the shoe being run and the hanger should be tracked. If kick indicators are present, then the shut-in sequence will depend on the whether the following conditions are present:

- Casing/liner inside the SBOP or riser
- Hanger is below the SID

- Drillpipe is in a position that allows the well to be shut-in

A crossover is needed to connect drill pipe to casing/liner.

4.3.2.9 Hang-off Guidelines

On floating rigs, hanging-off on designated hang-off rams is an essential part of the close-in and kill procedure. Depending on the equipment and rig configuration and capabilities, hang off may be possible at the seabed using a ram in an SID or at surface using a ram in the surface BOP.

In either case, the tool joint must not be placed opposite pipe rams or shear rams. For this reason, precise instructions and drills on spacing and landing the string are helpful. All concerned must know exactly where the tool joint is. Closing the rams on a tool joint would have dire consequences in a real emergency situation. If a circulating head is to be used in well kick operations, the hang-off procedure will include the installation of a circulating head.

Hanging off on the surface BOP rams will transfer load to the riser tensioners. Depending on the rig capabilities and the system design, the riser tensioners may not be capable of supporting this additional load. All personnel must be familiar with the system design and limitations before hanging off pipe in the surface BOP.

Depending on the system, hanging off a small portion of the drillstring weight will be sufficient to activate the drill string compensator and avoid any wear due to heave in the blowout preventer being used.

The following describes conditions related to hanging-off the drillstring. Consideration should be given to hanging-off the drillstring if any of the conditions listed in the following table exist during well control operations and the system is designed to accommodate hang-off:

Hang-off on Surface BOP Ram

Consider hanging off if:

- The ram BOP is closed
  - To prevent element wear due to vessel heave.
  - The location of the tool joint should always be verified before closing any pipe ram
  - Verify the riser tensioners can accommodate the load to be hung off
  - If hang-off ram is a VBR type, verify that string weight is within hang-off capability for the drill pipe size in the BOP
  - Specify if rams are to be locked after closure (if independent locks)

- Weather and sea conditions are creating excessive heave or severe loop current
    - Can result in wear damage to the annular BOP element
- Drillstring is attempting to stick
    - Need an early decision to ensure that drill pipe hang-off can be accomplished while string is free
- Motion compensator cannot prevent the drill pipe from moving through the annular due to vessel heave
    - Ensure that motion compensator is set to value greater than the weight of the drill pipe above the BOP, but less than total string (to place some weight on hang-off weight on the ram)
- Casing pressure increases above operating limits for the annular with/without drill pipe movement

Hang-off on SID Ram

Consider hanging off if:

- The ram BOP is closed
    - To prevent element wear due to vessel heave.
    - The location of the tool joint should always be verified before closing any pipe ram

  - If hang-off ram is a VBR type, verify that string weight is within hang-off capability for the drill pipe size in the BOP
  - Specify if rams are to be locked after closure (if independent locks)
- Weather and sea conditions are creating excessive heave or severe loop current possibly requiring disconnect
- Using dynamic-positioned rig where drift-off or drive-off incident has occurred, or where a mooring line failure as occurred that would cause large offset transient
  - There may be a need for immediate disconnect
  - May also apply to a moored rig if mooring line failure could cause an offset that exceeds slip joint/tensioner travel limits or would put excessive bending moment on the riser or structural casing
- Drillstring is attempting to stick
  - Need an early decision to ensure that drill pipe hang-off can be accomplished while string is free
- Riser angle at the SID is greater than established operating limit
- Unable to establish full returns, or evidence of an underground flow exists
- Riser pressure increases above operating limits

4.3.3 Circulating to Kill

A number of factors should be considered prior to implementing a method for circulating a kick to the surface. These factors include the following:

Gas

- Gas migration/location at shut-in relative to casing shoe

Circulation rate

- Slow pump data, rate selection
- Need to adjust DP pressure for new rate

Mud

- Mud viscosity data and effects

Fracture gradient

- Typically will be lower in deepwater

Mud/Gas separator loading

- May be higher in deepwater

4.3.3.1 Driller's Method

Advantages of the Driller's Method include a shorter time of influx in the well bore and a reduced probability of hydrate formation due to the following factors:

- Circulation brings wellbore heat up into the SID and the riser, helping to keep temperatures above hydrate temperature
- Reduced time and potential for hydrates to form (kinetics effect)
- Circulation tends to keep SID and riser equipment temperatures somewhat higher than a static well

4.3.3.2 Wait & Weight (Engineer's) Method

Advantages of the Wait & Weight Method include:

- Fewer circulations for total kill
- Reduced casing shoe pressure when the gas influx approaches that depth

However, as the distance from TD to the casing shoe in deepwater is usually minimal, this benefit is not likely to provide substantially lower casing shoe pressures.

4.3.3.3 Bullheading

Bullheading may be a viable alternative unless the open hole section is lengthy. Forcing influx fluids down the wellbore may induce underground inter-zonal flow. However, if the hole situation is favorable, bullheading may be best choice if other options would exceed pressure limits or excessive hydrogen sulfide is expected and.

4.3.4 Preventing Lost Returns and Underground Blowouts

In deepwater with long riser and high penetration rates, equivalent circulating density can increase significantly due to cuttings loading (slip velocity). The smaller riser sizes associated with surface BOP systems reduces this effect and a riser booster line is not required.

4.3.4.1 General Procedures for Detection of an Underground Blowout

The following indicators my provide evidence of an underground flow for various operations. If an underground blowout has occurred immediately initiate an appropriate response:

- If off bottom, strip to bottom using retrievable BPV

- Run pressure/temperature log to determine conditions and flow path

4.3.4.2 Underground Blowout while Drilling

Indicators of an underground blowout while drilling include the following:

Shut-in drill pipe pressure (SIDPP)

- Pressure may initially increase, but then should decrease, at least for a time
- Drill pipe pressure may fall to zero

Shut-in casing pressure (SICP)

- Pressure may initially increase, but then should decrease, at least for a time
- Pressure may be erratic then slowly increase as gas migrates to surface, potentially to very high values if the annulus is allowed to fill with gas

Note: If casing pressures have the potential to exceed casing, SID, riser and/or SBOP ratings, fluid (mud or water) can be pumped into the annulus to keep annulus pressure down. If pumping water, there is a potential for hydrate formation. If pumping mud, significant rates and mud volumes may be required and this should be planned *for as a contingency in advance of an emergency situation occurring.*

Gas displacement

- If there is no float in the drillstring, some DP mud may be displaced with gas if the pumps are stopped
- Casing mud can be displaced by some gas migrating upward, causing casing pressure to rise. If no response action is taken, this can rise to essentially the same pressure as downhole flowing pressure (less gas head), and may exceed casing or riser pressure rating. A response action to prevent this is to pump seawater or mud into the annulus at a moderate to high rate to keep it at least partially full of water and get the water hydrostatic to reduce casing pressure. Note that there is a potential for hydrate formation if pumping water into the annulus

Annulus pressure

- Able to strip drill pipe with no change in annulus pressure

Indicators of an underground blowout while producing or working a well over include the following:

Shut-in tubing pressure

- Pressure lower than normal on producing well with known or suspected tubing-annulus communication

Annulus pressure

- Pressure lower than normal on producing well with known or suspected tubing-annulus communication

Gas/oil ratio or water ratio

- Sudden change in ratio on producing well with annulus pressure

Vibration or drag

- Tree, drill pipe, and/or SID vibration on shut-in well
- Sudden tubing or drill pipe vibration and/or drag when lowered past point in well

4.3.4.3 Actions/Considerations in the Event of an Underground Blowout

Perform "positive test" to determine if borehole is a closed system.

- One indicator of an underground flow/blowout is no direct correlation of pressures on drill pipe and annulus

Make visual observation in the immediate are with the ROV and from the rig or support vessels on surface if underground flow is indicated in case of broaching at the mudline. A surface indication of broaching in deep water may be some distance from the rig.

- Visual from rig
- ROV
- Visual from support vessels

Strip the drillstring through annular to bottom to facilitate control if:

- Bit is significantly off bottom
- Drillstring is free

Run a temperature & pressure log.

- Pump water or mud down the annulus while running log if dictated by annulus pressure limitations
- Displace drill pipe with water or known density mud
- Pressure readings can be used to estimate flowing bottom hole pressure and the top of fluid in the drill pipe

Consider running a noise log to assess location and intensity of flow.

- Can be used as a baseline to confirm kill later

Consider running spinner log and other production logs.

- May be additionally used to look for a hole in drill pipe or tubing/casing

While running logs, begin evaluating procedures and logistics required if underground flow is confirmed.

Consider keeping the drill pipe full during an underground blowout.

- Prevents possible backflow and associated hammer effects if the well was to bridge off and the drill pipe float valve (if installed) failed

If needed to keep annulus pressure below casing or riser pressure limits, pump seawater or mud into the riser.

- Keeps casing and riser from completely filling up with migrating gas

4.3.4.4 Riser Damage

A different sort of lost returns can be caused by a leakage from the riser into the ocean. In severe situations the riser annulus level can fall, causing a reduction in bottom hole pressure and potentially an influx. Rig personnel should be alert that mud losses might be occurring in the riser (or connection lines). If riser level will not stand full, then the riser system is leaking. Riser buckling can be caused by insufficient tension, and can create a split and hole at the buckle point.

4.3.5 Hydrate Prevention/Removal

Taking a gas kick in a non-inhibited water-based drilling mud creates the potential for hydrate formation. Hydrates can form in the riser or behind SID rams, preventing them from opening. With a surface BOP system many of the difficulties caused by hydrates are avoided as the well control equipment is at surface and not subject to cold conditions.

The deeper the water, the more likely hydrates are to form because of both decreasing temperature and increasing hydrostatic pressure. At a 10 ppg hydrostatic pressure of 2,000 feet of water (1040 psi), the hydrate equilibrium temperature for methane is 48 degrees, just above the typical ocean floor temperature of about 46 degrees. In

4,000 feet of water, the equilibrium temperature is 61 degrees, 20 degrees above the typical water temperature.

There is a time factor for the formation of hydrates, both chemically and due to the cooling that occurs with time after circulation is stopped. Formation of hydrates during circulation is very unlikely due to the heat brought up from the wellbore, and the decreased time that gas is in the BOP.

The time factor favors the driller's method of well control. With the Wait and Weight Method, circulation must be stopped while increasing the pit mud density.

The time for Wait and Weight can be reduced if a sufficient volume of kill weight mud (of needed density) is already in the reserve. In addition, with surface BOP, higher rates of circulation are feasible greatly reducing the time spent circulating.

4.3.5.1 Inhibiting Drilling Mud with Salt

Salt may be used to achieve some hydrate depression for much of the wellbore. For maximum depression with NaCl (near saturated), the resulting mud density must be greater than 10 ppg.

Saturated salt can depress the formation temperature to about 36 degrees at 2,000 psi, or 40 degrees at 4,000 psi.

Because salt increases the density of the fluid, while drilling below shallow casings in deeper water, the fracture gradient may prevent the use of this fluid.

4.3.5.2 Alternatives to Salt Inhibition

The following identifies alternative drilling fluid inhibition methods:

Glycerol

- Commercial examples: HF-100, Aquacol-D.
- Additional hydrate depression of 8 degrees can be achieved with 5 percent concentration.
- Relatively expensive – often justifies improved mud solids treatment and recovery of the glycerol.

Synthetic-based & other non-water based systems

- Laboratory studies show that for effective hydrate inhibition, it is necessary to keep the salinity (typically $CaCl_2$) of the water internal phase above hydrate conditions
- Failure to maintain proper salinity may result in rapid hydrate formation (exceeding potential in water-based fluid)
- Gas dissolves more readily in synthetic fluids, bringing gas and emulsified water into close contact

- Dissolved gas is less likely to migrate during shut-in. This facilitates the use of the Wait and Weight kill method, if desired

  Note: Salt content in the water phase can affect the mud's shale stability performance.

Glycol

- Glycol may be injected via injection ports to SID components such as the connector using the ROV if required

Methanol

- Not a desirable mud additive because of toxicity and flammability issues

4.3.5.3 Hydrate Removal

Once hydrates form in subsea equipment or the riser, their removal is problematic. While concentrated inhibitor, such as glycerol, may decompose them, it may be difficult or impossible to get the inhibitor in contact with the hydrate, especially if a plug has formed. There are similar problems with heated fluid approaches, plus the tendency of heated fluid to be cooled before it can reach the problem area.

One technique involves pumping down coiled tubing run inside the drill pipe to a depth a few thousand feet below the hydrates.

Heat exchange with the annulus fluids both in the riser and below the mudline creates a complex thermal simulation problem whose results will depend on the site-specific situation. There are no 'rules-of-thumb' that will predict success.

Another potential approach is to run coiled tubing down the riser, this offers two choices:

- Circulate and wash glycol to bottom of the riser
- Nitrogen/air lift the riser to evacuate and reduce hydrostatic pressure to decompose hydrate

4.3.5.4 External Hydrates in the Wellhead Connector

Where near-mudline sediments can evolve gas (biogenic sources), there is the potential for hydrates to form in the locking mechanism of the wellhead-to-SID connector. Once formed, these can prevent unlocking of the connector.

There are a number of equipment options available with the connector and mud mats that can guard against such gas entering the connector.

Also, there may be inhibitor injection features, although these may not be effective in getting inhibitor to the hydrate. Operationally, these features should be checked (seal in place, injection lines not plugged) before running the SID.

4.3.5.5 Removing Wellhead Connector Hydrates

Procedure options to remove wellhead connector hydrates are listed below:

1. Circulate at a maximum rate (e.g., 3 pumps) with the drill pipe in the SID and specially selected nozzles.
   - Heat is generated by friction loss in the drill pipe and by dissipating hydraulic horsepower across the nozzles
   - Depending on mud pump capacity and water depth, this technique may require augmenting by surface heaters
   - Optimum rate, nozzle size, and whether/when to re-circulate returns can be determined by wellbore thermal simulation software
   - Modeling should include the temperature distribution from the inside of the SID out to

the outer diameter areas of the connector where the hydrate plugs are

2. Use an in-situ "heat bomb" to decompose the hydrates.
   - May be proprietary technologies and involve mixing of reactive chemicals to generate heat
   - Appropriate chemical recipe depends on several factors that should be assessed for specific conditions

3. After the well is appropriately abandoned, cut off the wellhead and pull it, along with the BOP and connector.
   - This obviously precludes subsequent use of the well

4. Spot methanol in small quantities via ROV.

   - A good hydrate inhibitor which can also dissipate a hydrate plug

   Note: Assess toxicity and flammability issues prior to action.

4.3.6 Well Control Prior To SID, SBOP and riser Installation / Shallow Water Flow

Prior to installation of the riser and well control equipment, shallow water flow control methods and techniques are the same as conventional deepwater subsea BOP operations. Refer to the IADC Deepwater Well Control Manual.

4.3.7 Plug and Abandon

In developing a plug and abandon plan, particularly for wells not initially drilled using SBOP, or drilled with SBOP and a larger riser, note that the size of all components such as casing hangers, seal assemblies, casing etc that can be pulled through a smaller diameter casing riser may be limited.

4.3.7.1 Summary

Deepwater affects the well control aspects of the following plug and abandonment operations:

- Casing perforating for lap squeeze cementing
- Casing cutting
- Seal assembly removal

In wellhead removal during subsea well abandonment, there is potential for gas to be in the casing/casing annuli underneath the casing seal assembly. On subsea wellheads, there are generally no openings to these annuli to check for and bleed this gas. Therefore, there is potential for release of this gas when the annulus is exposed by removing the seal assembly, cutting casing, or even perforating the casing for squeezing.

Gas can accumulate in the casing annulus by several mechanisms. One sequence that is brought about by deepwater occurs in the following scenario:

1. Casing is set through a hole section that contains permeable zones, one or more of which contains gas.
2. The casing seal assembly is set, isolating the top of the annulus from the mud hydrostatic above.
3. Filtration/seepage losses into the downhole permeable zones occurs.
4. The lost volume is made up by expansion of the annulus mud, and there is an associated loss of pressure in the annulus. At some point, the pressure under the seal assembly may reach zero, and no further pressure loss will occur. The amount of pressure that can be lost is a function of water depth and wellbore pressure profile.
5. The pressure decline may attempt to fall below that in a permeable zone elsewhere in the wellbore. If this is opposite a gas zone and occurs before

adjacent cement sets, some gas will enter the wellbore.

6. Influx gas will likely migrate up the annulus. What happens next depends on many factors. An annular gas flow can develop, or the gas can simply migrate up to the wellhead without any further fluid movement. Either way, a bubble of over-pressured gas exists below the seal assembly.

4.3.7.2 Perforating Prior to Squeezing of Casing Lap

It is often necessary to ensure that the annuli between casing strings are sealed as part of abandonment. If the top of cement of an intermediate or production casing was not brought above the previous casing shoe (as is often the case), then cement can be squeezed through casing perforations into the casing overlap. When perforating the casing for this squeeze, crews should be prepared for and alert for possible pressure buildup due to gas behind the casing. If the well does flow upon perforating, the planned shut-in and well control procedure should be implemented (e.g., close annular or shear rams).

If there is a strong likelihood of such gas other approaches are:

- Use the drill string as a lubricator to a distance well below the SBOP (with sufficient string weight to avoid pipe movement when shut-in under pressure), shut-in, then run the perforating gun through and below the drill pipe using a lubricator

- Run a short length of pipe below the SBOP ram with a "donut" below the ram to prevent movement under pressure. Rig up a wireline lubricator to the pipe, close the SBOP pipe rams and run the perforating gun through
- Rig up a wireline lubricator directly to the top of the SBOP

  Note: Access to the SBOP for personnel may be difficult or hazardous due to the proximity of the riser tensioner lines that may break or in the case of a riser recoil event.

4.3.7.3 Casing Cutting

Often, it is decided to cut and pull any production and intermediate casings from a point somewhere above the respective previous casing shoes. Similar to the circumstance described for perforating casing in the previous subsection, there may be overpressure in the annulus. The precautions described in the previous subsection generally apply for this operation.

4.3.7.4 Seal Assembly Removal

When removing the seal assembly, trapped gas can escape, either rapidly if it is over pressured or slowly by simple migration. While flow can be monitored to determine if the preventers need to be closed, it may be a preferable precaution to close a BOP and pump down the drill pipe and up the riser to remove any influx and monitor flow.

Another precaution that can be taken is to perforate the casing immediately below the seal assembly prior to pulling. This approach can reduce the potential rate of gas influx because of the small perforation hole area.

4.4 Environmental Discharge Contingency Plans

4.4.1 Spill Response Plan

As with all activities that could result in an oil spill over water, surface BOP drilling operations should be conducted with a formal Oil Spill Response Plan in place. This plan will provide a pre-determined and systematic approach to handling any oil spill. Prior to conducting surface BOP operations, Operators should review their current OSRP and update the plan as required to include specific information on surface BOP drilling operations.

4.4.2 Planning

The objectives of the oil spill response plan will in general terms be to:

- Ensure the safety of people
- Identify and control of the source
- Manage and conduct a response to the spill
- Protect the environment
- Contain and recover the spill
- Recover and rehabilitate wildlife
- Remove the oil
- Minimize economic impacts
- Keep people, stakeholders and the public informed

4.4.3 Potential Sources

Sources of spills may be:

- Oil based drilling fluids
- Hydrocarbons following a well control incident
- Hydrocarbons resulting from a blowout
- Hydrocarbons from well test activities
- Fuel oil from storage tanks or transfer lines and hoses
- Oils and lubricants
- Sumps and drip pans
- Cooling water
- Flare or vent
- OWS
- Deck drains
- SBOP or SID component flanges or connections
- Casing riser connections
- Telescopic joint packer

4.4.4 Spill Detection

During surface BOP drilling operations regular visual inspection of the water surface should be conducted and logged. This may be done from the drilling rig and also from supply or standby vessels in the area of the rig. This is a requirement of the water discharge permit process in the Gulf of Mexico with similar requirements in other areas of operation.

Regular visual inspection of the drilling riser using the ROV should be conducted to ensure that no leaks have occurred. Pressure testing of the drilling riser on installation and at appropriate intervals during the well (e.g. after setting a casing string) should be performed.

Prior to observing a leak at surface other indicators may provide early warning of a potential leak. If any of the following indicators occur additional visual observations should be conducted:

- Failure of a pressure test
- Loss of returns while drilling
- Loss of returns while circulating a kick
- Low fluid level in the riser

4.4.5 Source Identification

If an oil spill is observed at surface, immediate attempts should be made to identify the source if it is not immediately apparent. All drilling operations and any other operations such as fuel transfer, mud mixing, maintenance activities etc should be suspended and thorough visual inspection made of the rig, its systems and the surface BOP system and riser. If possible a sample of the spill should be collected (refer to the Operators OSRP for sampling procedures). A full visual inspection of the riser and SID should be conducted by the ROV.

4.4.6 Source Control

When the source has been identified, measures can be taken to control the source and stop the flow of oil. In the event this is an uncontrolled flow from the riser, the SID will be activated, and the wellbore isolated. If necessary the riser will be disconnected and retrieved for repair or replacement prior to re-commencing operations.

In the event of a blowout, a relief well may be required. Surface BOP operations will be in general conducted in deep water and more remote locations. In planning the well, consideration should be given to how a relief well will be drilled if necessary, in an emergency situation. The water depth is likely to exceed the capability of many available drilling units in a given area of operation. Adapting an existing rig to surface BOP operations may take several weeks or months to accomplish. In order to be capable of drilling a relief well at least one rig in the region of operation should be identified as being capable of drilling a relief well should an emergency occur. This rig may be equipped with conventional subsea BOP systems or surface BOP drilling systems. If the only rig available has a subsea BOP and marine riser, the wellhead on the proposed SBOP well should be deigned to permit operation with a subsea BOP including size and foundation strength (loading and bending) requirements

4.4.7 Reporting

Reporting of oil spills is a regulatory requirement and the procedure will be described in the OSRP.

4.4.8 Technical Expertise

The oil spill response will utilize an Incident Command System. The Incident Commander should have access to additional technical expertise on surface BOP operations as part of the spill response plan. Well control and fire fighting specialty companies retained as part of the OSRP should have expertise in surface BOP operations from floating rigs. This may initially require training and exposure to the equipment and its operation. This may be accomplished by including these companies in hazard identification, risk assessment and hazard and operability exercises, well planning and pre-spud meetings and any other rig based training.

4.5 Emergency Response Guidelines

From the perspective of Emergency response procedures, there are not many things that are significantly different between SBOP operations and standard operations. While the equipment used is different, the risks and potential emergency situations are broadly the same. Consequently the emergency procedures to be followed will generally be the same for either type of operation.

The rig used for SBOP operations will already have an extensive emergency procedures manual as part of the Drilling Contractors Safety Management System. This manual will cover emergency response procedures for conventional operations. Where an emergency is SBOP specific (as described in these guidelines), these guidelines are to be used to develop rig specific procedures that are to be followed as much as reasonably possible.

The following sections detail SBOP specific risks, and procedures, which will not be covered in an existing Drilling Contractors SMS documentation.

Senior rig personnel should be familiar with SBOP specific emergency response procedures and have a good working knowledge of SBOP specific risks and limitations, such that in the case of any emergency situation the correct course of corrective action is selected and followed without wasting any time or compounding the emergency by taking inappropriate action.

4.5.1 Well control

Deepwater drilling using a surface BOP is not a new concept; to date in excess of 150 wells have been drilled from floating rigs using a SBOP. A rig specific SBOP Well Control Procedures (WCP) manual should be developed, which will be the reference for any well control issues when operating with the SBOP system. Well control is covered in more detail in Section 4.4 of the Guidelines.

4.5.1.1 Procedures

The well kill technique to be followed in a particular situation will be dependent upon the well conditions recorded following shut-in, and the ongoing operations at the time of the incident. Each procedure requires careful planning and execution. During any such situation the Operators Drilling Supervisor and the Drilling Contractors Senior Toolpusher will only proceed with the well kill once an organized and well thought out kill plan is in place.

The following points provide a summary of the main differences between SBOP operations and Conventional Subsea BOP operations:

- Well control will be performed using the surface BOP
- Well control procedures to be followed will be very similar to those used for Jack-up operations
- Hard shut is recommended and the rig should be set up for hard shut in at all times while drilling
- The drillers method is recommended to circulate out well fluids
- In general terms the SID is not to be used as, or considered to be, a well control device, other than in special cases
- In certain circumstances the SID adds an extra option with regard to well control. For instance, in the case of a leak below the lower pipe rams, it is possible to shut the well in by closing the blind/shear rams on the SID, and then to fix the leak. However, closing the SID in any such situation must be considered carefully as it may have detrimental effects, in particular with respect to recovering any pipe sheared in the SID
- In the case that the flow cannot be stopped with either the SBOP or the SID, all non-essential crew should prepare to evacuate and preparations should be made to perform an emergency disconnect and for the rig to move off location

The worst possible scenario would involve a loss of station keeping ability, leading to an emergency disconnect, while circulating gas/hydrocarbons from the riser. This would most likely lead to a hydrocarbon spill, significant damage to the riser and the potential for damage to the rig. This scenario has been considered in previous QRA that have indicated that the probability of this occurring is so small, that this becomes an acceptable unlikely risk.

4.5.1.2 Diverter

Under normal well control operations with the SBOP the diverter will not be required, other than as a simple/convenient connection piece. However, in extreme emergencies (e.g. in the extremely unlikely case that the SBOP system fails completely), the diverter can still be actuated to direct any gas or fluids flowing from the well overboard through the vent lines.

One other scenario where the diverter system will be used is after a well control situation just prior to opening up the SBOP. In this instance the diverter will be closed in order to divert any gas trapped in the top of the SBOP overboard, rather than allowing it to bubble up onto the rig floor.

4.5.1.3 Hydrocarbons circulated to the surface

Well fluids circulated to the surface will be collected in the mud pits, from where they can be collected for conditioning. If any gas is circulated to the surface, this will be separated from the fluids in the mud/gas separator. The gas will then be vented from a pipe located in a safe location at the top of the derrick.

4.5.2 Emergency Disconnect

In certain extreme emergency situations or in the case of extreme weather, it may be necessary to disconnect the riser from the SID at the seabed in order to avoid damage to the well, or to the rig, or to reduce risk of an incident involving the personnel on the rig. Situations requiring a disconnect are the same as currently exist for a conventional subsea BOP.

Due to the consequences of performing an emergency disconnect, which in extreme cases could lead to some pollution, damage to the rig, the riser system, and / or the well itself, this is not an action which should be considered lightly, or undertaken without good reason. However, it is necessary that responsible members of the rig crew be empowered to take such action in an emergency situation without having to defer to others or waste valuable time, so as to ensure the safety of all personnel.

4.5.2.1 DP Operations

The criteria for the alert states and watch circle actions form the basis for the emergency disconnect procedures for operations with the SBOP system. As such they must be agreed by both the Drilling Contractor operations manager and Company operations manager before operations begin. The disconnect philosophy and procedures must then be communicated to the relevant crew members, and then copies of the table and diagram must be posted in the following locations:

- Drillers Control Room
- Toolpushers office
- Bridge
- Company office
- Engine control room

In all situations the DP Operator on the bridge is responsible for setting the Alert state of the rig which is notified to the driller by a Green, Amber or Red light. During Normal conditions the Green light should always be on, highlighting that everything is normal and operations can continue.

As conditions deteriorate as per the criteria listed on the Alert State Diagram, the DP Operator will successively change the Alert state, from Green, through Amber, and then in extreme cases Red. As a minimum the DP Operator will use the Alert state lights to notify the Driller, however if time allows the intercom from the bridge should be used to ensure that the driller is aware that this is not an exercise. If there is an exercise with the status lights, a warning must be given in advance.

4.5.2.2 Disconnect philosophy

This general philosophy should be considered whenever a disconnect is a possibility. If time allows as in the case of deteriorating weather every possible action should be taken prior to disconnecting from the well in order to:

- Make the disconnect procedure as safe as possible for personnel on the rig
- Minimize damage to the environment
- Ensure that the well is left in as secure a manner as possible
- Minimize damage to equipment

4.5.2.3 Disconnect procedure - drill pipe or nothing across SID

In any case when there is either nothing in the hole or there is only drill pipe across the SID, the following standard disconnect procedure can be implemented:

- In the case of a deteriorating situation the DP Operator will change the Alert state from Green to Amber and then potentially to Red
- If time is available to the driller (oral communication between the driller and the DP Operator will confirm this) as the Alert state changes he should make all efforts to:
- Pick up off bottom and space out the drill string to place a clean pipe joint across the SID
- If time allows, pull drill string above SID
- Bleed down the tensioners to a safe tension level to disconnect (if time allows)
- Set the DSC to lift the drill string 5-10 ft after the first shear ram cuts the pipe (if time allows)
- As soon as the Alert state change to Red, the driller should immediately activate the EDS system to effect the disconnect sequence

4.5.2.4 Disconnect procedure - non-shearable components across SID

In any case that an un-shearable component must be run through the SID, the philosophy is to cut the string at surface when the Amber alert state is reached and to allow the assembly to drop. This will ensure that if/when the Red alert state is reached there will be drillpipe across the SID.

The following procedure must be followed during the time that the un-shearable component is in the SID.

Prior to running any un-shearable component into the SID

- The Toolpusher must be consulted
- Toolpusher to confer with DP Operator on the bridge to confirm that:
    - The weather outlook is stable
    - DP system is operable and stable
    - Current is stable
- Toolpusher to confirm that the Autoshear circuit on the SID is disabled
- Driller to be prepared to perform a surface shear of the drill string using the SBOP shear/blind rams.
- Verify that communication between Toolpusher, DP Operator and the Driller can be established at any time.

In the case that the Alert state changes to Amber while there is a non-shearable component inside the SID

- DP Operator to change alert state indicator to Amber and to ensure that the Driller and Toolpusher are notified of this URGENTLY
- If time is available to the driller (oral communication between the driller and the DP Operator will confirm this) as the Alert state changes he should make all efforts to:

  - Move the un-shearable item above or below the SID
  - In the case that no time is available the driller must immediately space out the drill string at the SBOP shear/blind rams and close the shear/blind rams to cut and drop the drill string

When the Alert state changes to Red:

- DP Operator to change alert state indicator to Red and to ensure that Driller and Toolpusher are notified of this URGENTLY
- Driller to execute an immediate Emergency Disconnect of the SID

4.5.2.5 Re-entry after disconnect

Pay attention to the wellhead pressure, since hydrocarbons might have accumulated under the SID rams. Calculate the required mud weight to overcome the wellhead pressure before opening the rams.

A pressure test is required after the successful re-connect. An RTTS packer might be used in case of an open borehole.

- Unlock drill string compensator and stroke open
- Pick up a stand of drillpipe

- RIH with drillpipe and position connection below the lower pipe rams
- Close lower pipe rams
- Decrease closing manifold pressure on rams to 500 psi and strip up through rams until handling tool is seated below rams. Increase closing pressure on rams and lock rams
- Reset the acoustic system (if applicable)
- Stab hot stab into riser connector latch receptacle
- Verify with ROV that the riser connector on the SID is in open position and ring gasket is in place
- Pick up a pre-determined amount of load plus block weight.
- Position rig over wellhead
- Grab MUX cable subsea wet connect with ROV and pull away to one side (if applicable)
- Observe with ROV
- Bleed off tensioner pressure and land hub of lower transition joint in riser connector. If necessary use ROV to nudge riser into position
- Using ROV, pump into riser connector, latch connector with full operating pressure. Make visual confirmation that connector has closed. Hold pressure for 5 minutes and then bleed off pressure to manufacturer recommended value
- Use ROV to reconnect the MUX cable to the receptacle on top of the SID (if required)
- Adjust tensioners to support string weight including SID (neutral weight without overpull).

- Bleed off DSC to support weight of SBOP handling tool. Unlock and open upper pipe rams.
- Perform overpull test with a pre-determined overpull above string weight and then bleed down to normal operating tension
- Use ROV to check wellhead pressure and to pump open upper and lower SBR

4.5.3 Riser leak

The major concern if a leak develops in the riser is the ability to keep the hole full of mud. Failure to keep the hole full of mud will lead to loss of hydrostatic head on the formation, and may allow the well to flow.

The actions taken if a leak in the riser is suspected will be driven by current operations.

4.5.3.1 Leak During Normal Operations

Initial actions should include:

- Riser to be kept full of mud from trip tank
- Man stationed on drill floor to confirm that riser is full
- Establish loss rate

- Inspection by the ROV in an attempt to identify the leak.

If the ROV is unable to identify the leak the drill string should be pulled above the SID. The riser can then be pressure tested against the upper SID SBR and the SBOP annular.

Note: At least one manufacturers SBR's are designed to be tested from above to 1/3rd of their rated working pressure.

If pressure testing the riser confirms a leak, but the ROV is unable to identify it, the next option is to run an RTTS Packer and pressure test the riser until the position of the leak is identified. The decision can then be made to close in the well at the SID, recover the riser and repair the leak.

It should be noted that there is a strong possibility of damage occurring to some of the riser threaded connections, and hence riser should only be pulled back if absolutely necessary as it may subsequently be impossible to run without re-cutting threads.

4.5.3.2 Leak During Well Control Operations

Depending on the operation, pipe position, and severity of the leak, there are various options as to the immediate action to be taken. These may include:

- Continuing with the well kill operations
- Pumping LCM into the annulus
- Closing the SID
- Recovering and repairing the riser

Ultimately, in all cases of the riser developing a leak, the riser will have to be recovered and repaired before operations can continue.

4.5.4 Tensioner Failure

In order to get the best possible performance from the riser tensioner system, it should have equally divided loads around the load ring. This is to avoid bending moments and side loading of the riser string. In the event of a riser tensioner failure corrective action may be required to prevent damage to the riser. This will be dependant on the configuration and redundancy of the riser tensioner system.

In the event of a riser tensioner failure:

- Suspend drilling operations and monitor the well.
- Increase the tension load on remaining riser tensioner lines except the line opposite the failed line. Share the load equally between the remaining lines
- Reduce the tension in the line opposite the failed line
- At this point, depending on the circumstances, measures may be taken to secure the well.
- Repair the failed riser tensioner and return to service. Share the riser load between all in service tensioner lines

Drilling operations may not resume until adequate riser tensioner redundancy is restored (according to API 16Q)

4.5.5 Hydrates

When drilling in deep water, well pressure and temperature at the seabed are usually favorable for the formation of natural gas hydrates. The higher seafloor hydrostatic pressures and lower temperatures encountered increase the likelihood of hydrate formation inside and outside of the subsea wellhead and SID. When natural gas hydrates occur, they can form a blockage in subsea components and mechanically prevent closure of valves and BOPs.

4.5.5.1 Hydrate around the SID

In general, it is not uncommon to observe gas bubbles outside the structural casing. The gas bubbles accumulate and form hydrate on the outside of the SID, wellhead connector and the subsea wellhead. This can be mitigated by the use of hydrate exclusion seals and the injection of glycol into and around the wellhead connector.

4.5.5.2 Hydrates inside SID

There are two main situations of hydrate formation inside the subsea wellhead and bottom part of the SID.

- During a well control situation, when gas arrives at the wellhead
- When the well is closed for a long period of time if there is gas migration

In the first case, using a subsea BOP, the consequence might be the plugging of the kill and choke lines. This risk is minimized with the SBOP system, because the well is controlled at surface. It is considered to be unlikely that hydrates will block the SID while circulating out a kick.

The second case is similar for both surface and subsea BOP systems. If the well is to be shut-in at the seabed, gas can potentially migrate and assemble below the blind ram and hydrates may form. To mitigate the risk of hydrate blockage, glycol may be injected into the SID using a port between the rams. Glycol may also be injected into the wellhead and the riser connector.

4.5.6 Hydrogen Sulfide

The possibility of encountering H2S depends on the local conditions. If there is the potential for H2S in and area, all standard procedures for the detection of H2S and protection of personnel shall be put in place prior to drilling out the conductor casing shoe. Procedures should include cascade breathing system and on-board training and drills.

Due to the hardness of high strength casing (such as P-110) they are susceptible to sulfide stress cracking with the consequences of potentially catastrophic failure of the riser.

In the event that H2S is encountered while using a high strength casing riser and the H2S cannot be controlled by conventional means, the well should be bullheaded and abandoned.

4.6 Planning and Preparation Guidelines

The integrity, and hence the safety of wells depends on many factors, including design, construction, maintenance, intervention and abandonment. Through planning, monitoring and feedback, and by observing stringent standards and procedures, we control each of these factors ensuring that:

- A life-cycle management system is implemented which satisfies not only legislative requirements, but also the requirements of business needs; identifying key organizational roles and responsibilities, assigning accountability, setting standards of performance, measuring performance and allowing evaluation, comment, correction and improvement.
- Wells are designed and constructed with full consideration of all hazards and all relevant standards with the aim of reducing risk to people, the environment and our business to as low as reasonably practicable (ALARP).
- Well integrity is maintained throughout its' lifecycle by competent people using up-to-date written procedures and safe work practices.
- Quality assurance and control principles are applied, implemented and regularly reviewed which

identifies responsibilities and procedures and ensures the design intent is being realized.

- Co-operation and effective communication is maintained with third parties and appropriate authorities.

In respect to design, procurement and construction specifications, the strategy is one of standardization and simplification. Functionality is the ultimate aim for the specification of design, materials and construction.

Implementation of a goal setting regime strategy applicable to all surface BOP activities is achieved through the definition of performance standards for all aspects.

It is realized that by setting performance standards for any aspect of our business we are defining acceptability. The methods we adopt in achieving these standards are referred to as Performance Assurance Processes. This framework is depicted in Fig. 2.1.

4.6.1 Performance Standards

The performance standards for surface BOP activities are segregated into three areas, covering both the facilities and management systems. These are the subsurface hydrocarbon system, operating procedures and integrity management.

4.6.1.1 Sub-Surface Hydrocarbon System

Objective

To ensure that the sub-surface hydrocarbon inventory connected to an installation is contained within the wells and to ensure the capability to construct a well and perform intervention operations.

Purpose

To provide all necessary equipment, materials and services for well construction and intervention activities.

Functional Requirements

Subsurface Hydrocarbon Envelope

To ensure riser and wellhead assembly, tubing and casing strings contain the well fluids and pressures and support the imposed loads during all phases of well construction, production, intervention and abandonment operations for all defined operating conditions.

Well Control Fluids

To safely control inflow of well bore fluids during construction and intervention operations.

HP Riser & Pressure Control Equipment

To ensure well bore fluids containment during open and cased hole operations, including wireline and coil tubing. To provide through pressure control equipment a means of isolating the well inventory in the event of operational failure or unexpected condition in well.

Tensioning System

To ensure rig tensioning system provides adequate support of the riser and BOP for all defined operating conditions and in the event of operational failure.

Mooring System

To ensure rig mooring system maintains desired station keeping performance to minimize loads on high pressure riser system for all defined operating conditions and in the event of operational failure.

Reliability and Availability

Capability to isolate, contain, control and segregate hydrocarbon system to retain sufficient integrity to minimize the release of inventory and escalation.

Survivability

Hydrocarbon system designed and maintained such that a rupture of the system once isolated and segregated will not escalate the release event and the threat to personnel on the installation.

4.6.1.2 Integrity Management

Objective

To ensure that the integrity of the well is maintained.

Purpose

To provide practices and procedures for ensuring the integrity of the well including measures to ensure that all modifications and operational changes are in accordance with performance standards and that there is a means of performance reporting and an audit-able record for the assurance of integrity.

Functional Requirements

<u>Practices and Procedures</u>

Practices and procedures by which all work will be performed that are technically correct, up to date and easy to understand and follow on the rig.

Change Management

To ensure that operating criteria changes (facilities, procedures, and people), proposed modifications and projects meet the appropriate system Performance Standards.

Maintenance & Inspection

To undertake actions to ensure that critical equipment is maintained for safe operation through all phases of the well life cycle within the defined operating envelope.

To monitor the condition of equipment and systems in determining preventative action necessary to mitigate the effects of failure.

To ensure that all temporary equipment is installed and integrity maintained in accordance with fixed equipment procedures.

To confirm the continued integrity of the well and to identify any signs of deterioration of critical components.

Reliability and Availability

The effectiveness of Integrity Management activities to be assured through SBOP Management Systems

Survivability

Ensure procedures and practices are updated and followed through management systems, supervision and audit.

4.6.1.3 Operating Procedures

Objective

To ensure the safe design, construction, maintenance, intervention and abandonment of the well through documented activities executed by all personnel.

Purpose

To provide documented practices and procedures for all personnel including procedures critical to safe operations with defined accountabilities and responsibilities

Functional Requirements

A structured hierarchy of documents that define work procedures for all surface BOP related well activities.

Reliability and Availability

Effectiveness of operating procedures assured through Management System.

Survivability

Ensure procedures and practices are updated and followed through management systems, supervision and audit.

4.6.2 Performance Assurance

Performance Assurance describes the activities to be conducted to ensure the defined Performance Standards are achieved. These are defined according to the breakdown of each standard into one or more critical sub-systems. These performance assurance processes provide an outline of what has to be achieved and how this will be done in order to meet the required performance standard.

4.6.2.1 Sub-Surface Hydrocarbon Envelope

Objective

To ensure riser and wellhead assembly, tubing and casing strings contain well fluids and pressures and support the imposed loads during all phases of well construction, production, intervention and abandonment operations for all defined operating conditions.

Functional Requirement

The system shall be capable of handling the maximum anticipated flow rates, well fluid characteristics, bottom hole pressures and temperatures subject to installation constraints. Materials shall be selected in accordance with desired design life and anticipated well conditions.

Ensure well life is capable of meeting or exceeding the specified well design life by reviewing the well design against required well conditions detailed in design basis

Ensure that well construction provides sufficient pressure boundary integrity to guard against hydrocarbon releases by use of adequate casing riser. Casing selection will be made on the basis of desired well life and design conditions including environmental and metocean.

Ensure sufficient pressure boundary integrity to guard against hydrocarbon releases by use of adequate wellhead. Wellheads to provide containment of annulus contents.

Where deemed necessary and applicable to provide a facility for seabed shut-in and ensure sufficient pressure boundary integrity to guard against hydrocarbon releases by use of adequate valving.

Provide a facility for well abandonment or repair ensuring that the necessary isolations can be established prior to work commencing.

Take due account of any casing or riser wear during drilling, abandonment or other types of remedial work. Model casing wear using a casing wear program if appropriate.

Ensure that mud hydraulics meets the pore pressure and over balance requirements. Review well design against required well conditions detailed in the design basis

Reliability and Availability

Where installed, seabed shut-in devices will close on demand in the event of an emergency. The device will have a reliable control mechanism with back up.

Survivability

The seabed shut-in device if installed will continue to contain hydrocarbons. The design should use proven technology with measurable reliability.

4.6.2.2 Well Control Fluids

Objective

Safely control potential for inflow of well bore fluids during construction and intervention operations.

Functional Requirement

Ensure drilling/intervention fluid provides sufficient pressure boundary integrity to guard against hydrocarbon releases.

Ensure that well specific hazards with regard to riserless drilling for surface hole are identified, sufficient barriers out in place and mitigation measures identified in the event of shallow gas

Reliability and Availability

Ensure sufficient fluid volume at he correct density is available to permit operations to proceed without inflow of the well bore fluids. Keep sufficient barite available on location to permit an increase in fluid weight of at least 1.0 ppg. The daily mud report should be completed stating current stock levels, mud density etc.

Survivability

Fluid remains active providing overbalance pressure irrespective of installation incident. Conduct daily fluid checks during operations including a review of pore pressure estimates and riser margin.

4.6.2.3 High Pressure Riser and SBOP

Objective

Ensure well fluids containment during open and cased hole operations, including wireline and coil tubing. Provide by means of surface BOPs a method of isolating the well inventory in the event of operational failure or unexpected condition in the well.

Functional Requirement

Ensure that the BOPS are rated to bottom hole pressure plus kill margin and that pressure control equipment is designed and constructed in accordance with industry standards.

Reliability and Availability

Ensure inspection and maintenance program for pressure control equipment is designed to reduce the frequency of failures to a level that is ALARP. Confirm the inspection and maintenance system is being implemented by management systems and audit.

Survivability

Maintain riser angle limit and vessel offset
Observe sea and weather state and regularly monitor weather reports
Monitor well control parameters and undertake condition monitoring during incidents
Identify potential disconnect conditions according to pre-determined disconnect parameters
Monitor current with ADCP or instrumented riser

4.6.2.4 SBOP Support System

Objective

Provide structural support to BOP and high pressure riser system

Functional Requirement

Ensure that the HP Riser and SBOP system is supported throughout all drilling, intervention and well control operations within design operating tension envelope.

Determine required tension operating envelope during well design stage. Ensure monitoring of riser tension during all operations. Ensure integrity through maintenance & inspection program. Detailed procedures are to be in place for tension adjustment due to cementing, tide or other operations.

Reliability and Availability

Ensure that inspection & maintenance program for riser support system is designed to reduce the frequency of failures to a level that is ALARP. Audit the inspection and maintenance program to ensure implementation.

Ensure that SBOP and HP Riser system cannot impact underside of drill floor with sufficient energy to cause structural damage or injure personnel. A riser recoil system is to be installed if necessary.

Survivability

Ensure that a static system is in place to support BOP & Riser in the event of any installation tensioner system failure. Sufficient tensioner capacity to allow failure of one tensioner (or one pair of tensioners) as per API RP 16Q - Recommended practices for marine riser design.

4.6.2.5 Mooring Systems

Objective

Ensure rig mooring system maintains desired station keeping performance to minimize loads on high pressure riser system for all defined operating conditions and in the event of operational failure.

Functional Requirement

Ensure that the system maintains station keeping requirements for the location specific operational and non-operational environmental conditions and maintain rig position within riser design tolerances. The mooring design and analysis should be completed satisfactorily for the location specific environmental conditions.

Monitor the rig position and adjust if and when necessary, (active winching) using Positioning equipment installed on the rig.

Reliability and Availability

System should maintain integrity in severe event design conditions. Ensure inspection and maintenance program for mooring system components is designed to reduce the frequency of failures to a level that is ALARP. The design environmental conditions should be reviewed and verified

Ensure that maintenance & inspection is being maintained through audit process.

Survivability

Ensure Mooring System maintains integrity in the event of the loss of one mooring line during operations or in the event of an extreme design condition.

The mooring analysis is to be performed for the loss of one mooring line, reference to API RP 2SK. Recommended practices for station keeping.

4.6.2.6 Change Management

Objective

To ensure that operating criteria changes (facilities, procedures, people), proposed modifications and projects meet the appropriate system Performance Standards.

Functional Requirement

To provide consistent change management controls with regard to changes affecting facilities, people and procedures.

Reliability and Availability

The management of change procedure shall form part of the Safety Management System.

Survivability

The effectiveness of the management of change procedure to be ensured through audit.

4.6.2.7 Maintenance and Inspection

Objective

Undertake actions to ensure that critical SBOP equipment is maintained for safe operation through all phases of the well life cycle within the defined operating envelope. Monitor the condition of equipment and systems in determining preventative action necessary to mitigate the effects of failure. Ensure that all temporary equipment is installed and integrity maintained in accordance with fixed equipment procedures. Confirm the continued integrity of the well and to identify any signs of deterioration of critical components

Functional Requirement

Ensure the integrity of the equipment on the installation so as to ensure its ability to perform its intended task safely and effectively. Maintain all temporary equipment. Ensure that all third party / contractor equipment is maintained as per fixed equipment standards.

Reliability and Availability

Maintenance and inspection shall be mandated by the rigs planned maintenance system

Survivability

Ensure effectiveness of the maintenance system through periodic audit process as defined in

4.6.2.8 Operating Procedures

Objective

Provide a structured hierarchy of documents that define work procedures for all surface BOP related well activities.

Functional Requirement

Provide operators of SBOP equipment with clear guidance for the installation, hook-up, commissioning operation and maintenance of the SBOP system.

Reliability and Availability

A set of documents describing all procedures and requirements must be produced and a full training program in these must be implemented.

Survivability

Ensure compliance and effectiveness by means of audit.

4.6.2.9 Operating Competency

Objective

Ensure that all personnel have sufficient competence through technical training, experience and competence assurance processes for the execution of their SBOP activities.

Functional Requirement

Take appropriate actions to correct deviations from the safe operating limits throughout SBOP well life cycle. Operate at a level of competency that ensures that equipment is within design safe operating limits. Ensure that all personnel accurately interpret Emergency Response actions to be taken as and when required. Ensure that well operations are performed within safe operational limits throughout SBOP well life cycle.

Reliability and Availability

Sufficient numbers of competent personnel are to be available to perform safe operations. A formal competency assessment process should be implemented for all key positions.

Survivability

Ensure compliance and effectiveness by means of audit.

4.6.2.10 Condition Monitoring During Operations

Objective

Continuous measurement of various parameters is critical during the surface BOP operations. These are essential for the integrity of the riser, which may be exposed to high-pressure hydrocarbons without the protection of BOP at the seabed

Functional Requirement

The following are to be monitored throughout the operation:

- Vessel Position
- Vessel Heave
- Riser stroke within moon pool area
- Weather forecast
- Current measurements (minimum hourly)
- Mooring loads (hourly)
- Vibration generated stresses on riser (optional)
- Riser wear (optional)

Reliability and Availability

Provide 24 hour accurate condition reporting with data acquisition system and backup data storage including weather and positional analysis, riser instrumentation or ADCP, casing wear log (if required). Design limitations must be addressed as part of operations procedures as decision trees in conjunction with site specific well design document.

Survivability

Data acquisition to be part of planned maintenance system and subject to daily checks.

4.6.3 Design Studies

In order to implement a surface BOP operation, understand and establish performance standards and implement performance assessment processes several detailed engineering studies are required. Technical information must be gathered and organized systematically to ensure all project and operations personnel are using up-to-date and correct information consistently.

4.6.3.1 HAZID, QRA and HAZOP

Risk assessment studies must be completed at the appropriate time during the design and implementation of a surface BOP system. Refer to section 4.2 of the Guidelines.

4.6.3.2 Mooring Design and Analysis

A detailed mooring analysis in accordance with API RP 2SK for the specific rig, mooring components and specific well locations using appropriate site-specific metocean data. The mooring analysis is to be performed in conjunction with the riser design and analysis. Refer to section 3.4 of the Guidelines

4.6.3.3 Riser Design and Analysis

A detailed riser analysis in accordance with API RP 16Q for the specific rig, riser components and specific well locations using appropriate site-specific metocean data. Refer to section 2.5 of the Guidelines. Determine riser offset limits intact and with 1 mooring line failed. For DP rig determine watch circle limits.

4.6.3.4 Interference (Clashing) Analysis

The potential for interference and clashing between the SBOP, tensioners and riser and the rig structure in and around the moonpool area must be checked for the full range of movement of the SBOP system. This should include all planned operating and survival design conditions with sensitivities covering unplanned events. Of particular interest is the potential for clashing in the event of a station keeping failure. Refer to section 2.4 of the Guidelines.

4.6.3.5 System Design

The complete SBOP system must be designed and configured for the specific rig to be used in the drilling program.

4.6.3.4 Inspection and Qualification of Equipment

Equipment that is to be re-used should be inspected according to the manufacturers recommendations prior to use. Newly designed or specialty equipment and components used in new applications should be fully qualified and tested for the intended service.

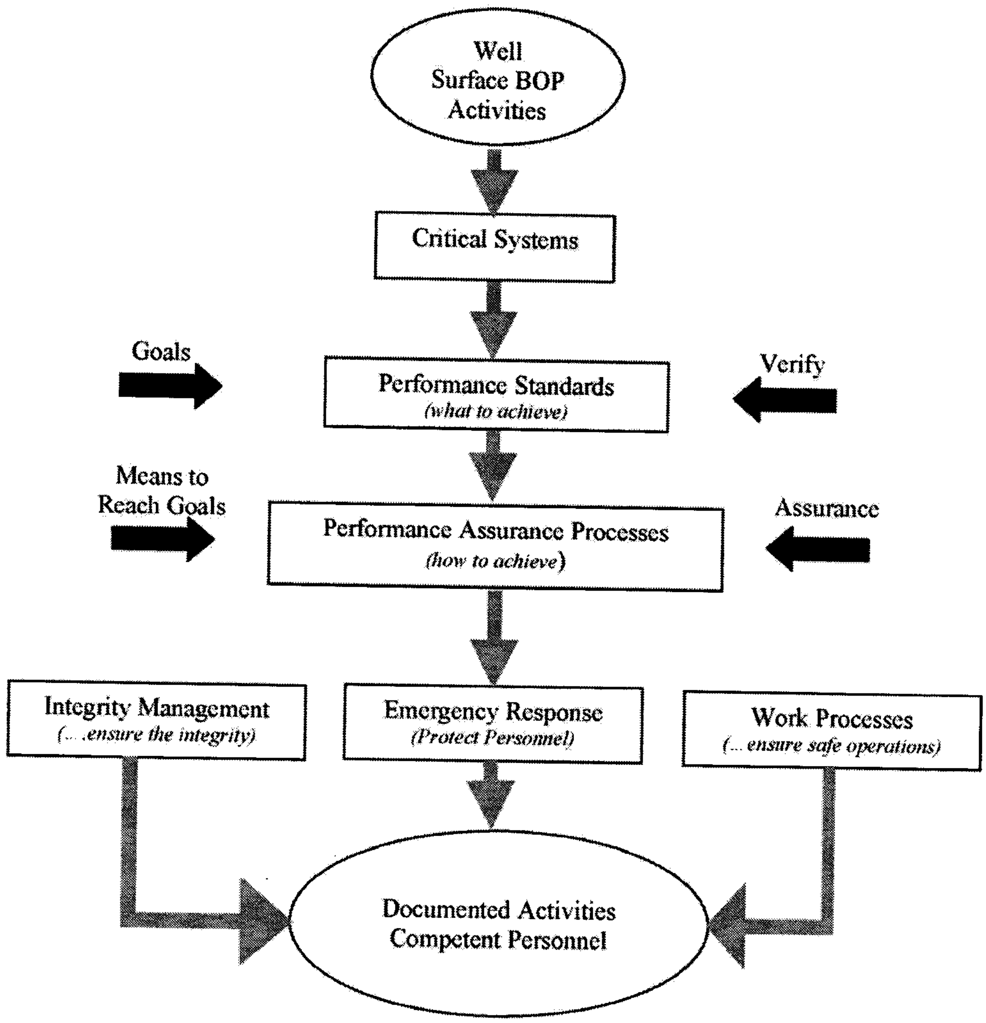
Well
Surface BOP
Activities
Critical Systems
Goals
Performance Standards
(what to achieve)
Verify
Means to
Reach Goals
Performance Assurance Processes
(how to achieve)
Assurance
Integrity Management
(... .ensure the integrity)
Emergency Response
(Protect Personnel)
Work Processes
(... ensure safe operations)
Documented Activities
Competent Personnel

Figure 4.6

4.7 Equipment Verification and Specification

This section describes the process used to enable the compilation of a "Safety Critical Equipment Description system" to comply with the requirements of the most stringent HSE regulations worldwide.

The objective is to set self-assuring standards and objectives in compiling a detailed matrix of Safety Critical Equipment. Once the safety critical equipment is identified the next step shall be to rank each system and sub-system using a Hazard Identification Code.

Identification and assessment of each identified critical system and sub-system is achieved by pooling combined knowledge and experience. A series of peer review meetings between all relevant personnel shall be conducted to determine the final critical equipment register and hazard assessment.

From the critical equipment register, performance objectives are developed for each critical safety equipment system. These ensure that equipment shall be manufactured to the required quality standards and maintained throughout the defined life cycle ensuring their functionality and reliability.

Equipment procurement pro-formas are introduced into the design stage to enable full understanding of the functional requirements, industry standards, specification documentation, certification and all other relevant information required for manufacture. The Project Lead Engineer (or Team Lead) shall be responsible for preparing these prior to ordering any equipment.

This philosophy makes the necessary links between the higher level Governing (Performance) Standards and the lower level Performance Objectives. This provides an auditable process satisfying goal setting requirements.

This approach can be summarized in the following manner:

- Define Performance Standards
- Define Assurance Processes
- Develop Critical Equipment Register
- Develop Critical Equipment Performance Assurance Objective Sheet.

4.7.1 Performance Assurance Objectives

Performance Assurance Objectives are a listing by item or component showing what criteria will be monitored or controlled, how they will be monitored, and the steps to be taken to ensure that the components will meet the criteria

The following performance assurance objectives relate to typical critical equipment for SBOP operations.

4.7.1.1 Drilling BOP System

Performance Objectives

- To shut-in well against the maximum anticipated surface pressure in the event of a kick.
- To allow circulation of the kick out of the well in a controlled manner
- To provide a means of killing the well by injection of mud to the annulus.
- To shut-in the well to prevent escalation of non-drilling events.

Performance Criteria

Closing time should not exceed 30 seconds for annular BOPs smaller than 18.3/4" nominal bore and 45 seconds for annular preventers for 18.3/4" and larger.

BOP system must provide capability to shut in and provide reliable closure for kill of the maximum anticipated well influx for the project

Performance Basis
API RP 16E Design of Control Systems for Drilling Well Control Equipment

API RP 53 Recommended Practices for Blowout Prevention Systems for Drilling Wells

Operators Well Control Manual

Performance Assurance Method

- BOP equipment to be third party inspected prior to commencement of project
- BOP Equipment, (rams seals etc), to be physically inspected between wells
- BOP equipment to be function and pressure tested to maximum anticipated well pressure on the test stump prior to installation on each well
- BOP equipment to be routinely functioned at pre-determined intervals during the well to verify correct operation

Other Assurance Methods

- Annual review by certifying body of planned maintenance system to meet regulatory requirements
- Annual third party inspection of BOP equipment and certification
- Auditing of manufacturers and drilling contractors safety systems

4.7.1.2 BOP Control System

Performance Objectives

The BOP control system supplies hydraulic power fluid as the actuating medium for operation of the BOPs. The elements of the control system include storage equipment for supplying control fluid to the pumping station, pumping systems for pressurizing the control fluid and accumulator bottles for storing pressurized control fluid. A hydraulic control manifold for regulating the control fluid pressure and directing the power fluid flow to operate the system functions (BOPs, choke & kill valves). Accumulators containing compressed nitrogen gas are used to further enhance the BOPs function response time and to serve as a backup source of hydraulic power in case of pump failure

Performance Criteria

Pre-charge pressure on each accumulator bottle should be measured prior to each installation of the BOP on each well and adjusted if necessary.

Pump system should have electric or air independent power sources and be capable of closing the annular BOP on the minimum size drill pipe being used, opening the hydraulically operated choke valves and providing the operating pressure level defined by the annular BOP manufacturer.

Response time between activation and complete operation of a function is based on BOP or valve closure and seal-off. A BOP is considered closed when the regulated operating pressure has recovered to its normal setting.

Performance Basis

API Specification 16D "Specification for Control Systems for Drilling Well Control Equipment".

API RP 16E "Design of Control Systems for Drilling Well Control Equipment".

API RP 53 "Recommended Practices for Blowout Prevention Systems for Drilling Wells".

Performance Assurance Method

The system is maintained, inspected and tested as part of the Drilling Contractors approved planned maintenance system.

All operational components of the BOP control system should be functioned regularly during operations to verify the component intended operations.

Function tests should be alternated from main and remote control panels if available. Actuation times and fluid volumes should be recorded as a database for evaluating trends.

Other Assurance Methods

Annual review by certifying body of planned maintenance system to meet regulatory requirements

Auditing of manufacturers and Drilling Contractors safety systems

4.7.1.3 Wellhead

Performance Objectives

The wellhead system provides:

- Containment and isolation to ensure pressure integrity to guard against hydrocarbon release during the operational life of the system
- A conduit for suspension and abandonment
- Structural support for various casing strings within the well.
- A means to safely contain well bore fluids within the design envelope
- A point of fixity at the seabed
- A load shedding mechanism in the event that a long string of surface casing is run

- An attachment point for the method of planned disconnect of the riser from the wellbore

Performance Criteria

The wellhead system must have sufficient structural integrity to withstand maximum design loads (tension and bending) and maintain the required pressure integrity

The conductor casing must be of sufficient size and length to support the loads imposed by the surface casing.

The system must provide sufficient load bearing capability for the designed surface casing load

Performance Basis

API Specs, Vendor manufacturing specifications and Operator standards

Performance Assurance Method

FEA on wellhead as part of riser design
Operator well design guidelines
Peer review of well design

Other Assurance Methods

Verification of vendor documentation for equipment specs

4.7.1.4 Riser Tensioner System

Performance Objectives

The riser tensioning system suitably upgraded if required to support the SBOP and the riser in tension under all operational load conditions and during all the design metocean conditions.

Additionally, the tensioning system is a safety critical component of the SBOP riser system. The tensioning system must be capable of holding the weight of the riser and SBOP equipment in tension and compensating for rig motion relative to the riser and wellhead under all design metocean conditions

Performance Criteria

The tensioners are to have sufficient capacity to support the riser in tension under all metocean conditions. The tensioners are to have sufficient reserve capacity to support the riser in tension with one (or one pair) of tensioners failed. The tensioner system is to have sufficient stroke to accommodate the maximum design offset.

Performance Basis

API RP 16Q Recommended Practice for Design, Selection, Operation and Maintenance of Marine Drilling Riser Systems

API RP 2RD Recommended Practice and Design of Risers for Floating Production Systems and Tension Leg Platforms.

Performance Assurance Method

Operator Peer Review of SBOP Riser Analysis

Tensioner system to be inspected and certified

Tensioner system sheaves and guide wires (if system used), to be visually inspected prior to start of each well

Tensioner wire ton miles to be recorded and used as a basis to change out tensioner wires before failures occur

Tensioner wire internal corrosion to be monitored and inspection performed prior to each use

Other Assurance Methods

Installation of reliable and calibrated tensioner air pressure vs. total tension weight measuring device

4.7.1.5 Casing Riser

Performance Objectives

The casing riser must be capable of providing satisfactory structural integrity against formation collapse, installation movement, burst or collapse pressures, current loads or other imposed forces.

The casing riser must provide a means of conveying the up-flowing drilling fluid from the well bore to the mud pits.

To Shut-in well against the maximum anticipated surface pressure in the event of a kick.

To allow circulation of the kick out of the well in a controlled manner

Performance Criteria

Casing selection made on the basis of desired well life and anticipated well conditions.

The casing riser is to be capable of containing the maximum anticipated surface pressure and to satisfy the anticipated well conditions without risk of failure.

The casing riser shall be designed to withstand the operational and environmental conditions as detailed within the relevant basis for design document (design envelope) without loss of integrity.

All casing riser is to be rated, tested and maintained to satisfy the anticipated well conditions.

Performance Basis

API Specification 5CT specification for casing & tubing

API 5A3 Thread compounds for casing, tubing & Line Pipe

API5A5 Field Inspection of new casing, tubing and plain end pipe

API 5B Specification for threading, gauging and thread inspection of casing, tubing

API5C1 Care and use of Casing, Tubing and Drill pipe.

API 5C2 Performance Properties of Casing, Tubing and Drillpipe

API 5C3 Formulas and Calculations for Casing, Tubing, Drillpipe and Line Pipe

API5C5 Evaluation Procedures for Casing and Tubing Connections

API-RP-16Q Recommended Practice for Design, Selection, Operation and Maintenance of Marine Drilling Riser Systems

API-RP-2RD Recommended Practice for Design of Risers for Floating Production Systems and Tension Leg Platforms

Section VIII, Division2 of the ASME Boiler and Pressure Vessel Code

NACE MR0175-98

Operator casing design manual

Performance Assurance Method

Casing dimensions, material grade, weight, pressure rating to be stated in well drilling program.

All riser casing to be rated, tested and maintained to satisfy the anticipated well conditions.

Riser casing to be pressure tested to maximum anticipated surface pressure.

All riser casing couplings to be Shell qualified gas tight premium riser casing couplings

Riser casing stock management program ensuring that casing used only once for riser application.

SBOP riser analysis load cases defined in SBOP Riser analysis basis of design and checked against the well basis of design

Peer review & acceptance of SBOP riser analysis basis of design document

Peer review of SBOP riser analysis results

Other Assurance Methods

Use of torque/turn measurement equipment during riser casing make-up

Visual inspection during preparation and running
Drift inspection during preparation

4.7.1.6 Seabed Isolation Device

Performance Objectives

The SID is to provide a means to:

- If required, hang off the drillstring
- Shear the drillstring components in the wellbore
- Isolate the wellbore at the seabed
- Disconnect the riser from the wellhead
- Reconnect the riser to the SID
- ROV intervention for critical functions
- Emergency disconnect (if required)
- Auto-shear (if required)

Performance Criteria

Shear the maximum shearable drillstring component in the well program

Seal wellbore to full working pressure

Capable of operating under maximum anticipated surface pressure in combination with tension and bending loads from riser

Dual redundant control methods from the rig

Performance Basis

API Specification 16D Specification for Control Systems for Drilling Well Control Equipment

API RP 16E Design of Control Systems for Drilling Well Control Equipment

API RP 53 "Recommended Practices for Blowout Prevention Systems for Drilling Wells"

Performance Assurance Method

- The system is maintained, inspected and tested as part of the Drilling Contractors approved planned maintenance system
- The system should be pressure tested prior to each use or after any maintenance or modification to the pressure containing components
- All operational components of SID systems should be functioned regularly during operations to verify the component intended operations
- Function tests should be alternated from main and remote control panels if available. Actuation times should be recorded as a database for evaluating trends BOP equipment to be third party inspected prior to commencement of project
- BOP Equipment , (rams seals etc), to be physically inspected between wells

Other Assurance Methods

- Annual review by certifying body of planned maintenance system to meet regulatory requirements
- Annual third party inspection of equipment and certification

4.7.1.7 Station Keeping System

Performance Objectives
To provide station keeping within the watch circle and maximum offset as defined by the project specific requirements.

Performance Criteria
Sufficient capability to withstand the maximum metocean conditions as required by the detailed riser design

Safety factors to be designed as per the Design Guidelines and API recommendations.

Component reliability and system redundancy to maintain station with one component failure (mooring leg or DP system)

Performance Basis

API-RP-2SK Recommended Practice for Design and Analysis of Station Keeping Systems for Floating Structures

Performance Assurance Method

Peer review of station keeping design
Key components to have sufficient redundancy
Inspection of critical components

Other Assurance Methods

Maintenance performed as part of Drilling Contractors planned maintenance system.

Critical Equipment Register

Critical System	Sub Elements	HAZARD SYSTEM IDENTIFICATION				Performance Standards	Performance Assurance Process	Criticality Rating
		Cause/ Contribute	Prevent	Detect	Control/Mitigate			
BOPs	Annular				✓			High
	Shear Seal				✓			High
	Variable Pipe Rams				✓			High
	Inside BOP				✓			High
	Fixed Pipe Rams				✓			High
	Wellhead Connectors		✓					High
	Gaskets		✓					High
	Gate Valves		✓					High
			✓					High
BOP Control Systems	Master Control Panel				✓			High
	Remote Control Panel				✓			High
	Valves				✓			High
	HP Hoses				✓			High
	Accumulators				✓			High
	Accumulator Unit				✓			High
	Choke Lines				✓			High
	Kill Lines				✓			High
	HP Piping				✓			High
	Choke Manifold				✓			High
	Kill Manifold				✓			High
	Choke				✓			High
	Choke & Kill				✓			High

Critical System	Sub Elements	HAZARD SYSTEM IDENTIFICATION				Performance Standards	Performance Assurance Process	Criticality Rating
		Cause/ Contribute	Prevent	Detect	Control/Mitigate			
	Medium							
	Instrumentation			✓				Medium
	Gauges			✓				Medium
	Transducer			✓				Medium
	Operating Fluids				✓			Medium
Wellhead	Hanger Seals		✓					High
3BOP	Valves		✓					High
Specific	Connectors		✓					High
	Gaskets		✓					High
								High
Riser Casing	Pipe Body		✓					High
	Connectors		✓					High
	Wellhead Connectors		✓					High
Riser Tensioner System	Tensioners							High
	Operating Fluid		✓					High
	Sheaves		✓					High
	Cable		✓					High
	Connectors		✓					High
	Pad Eyes		✓					High

Figure 4.7

4.8 Personnel Training

Any person who is involved in the drilling of a well (from the planning stage to the final plug and abandoning of the well) has some form of responsibility in preventing a kick or blow out. In order to carry out these responsibilities adequate experience and formal training is required.

4.8.1 Responsibilities

During drilling operations, each drill crew member should be familiar with the operation of all blowout preventer controls even though they may only have a specific task or responsibility allocated to them during well killing. Regular drills initiated by the Senior Toolpusher or Operator's representative will be carried out to help develop crew co-operation and skills. Spot check drills shall be initiated and closely monitored by the Driller to ensure that his crew remains proficient. It must be remembered that kicks can occur under a variety of circumstances and conditions such as; drilling ahead; tripping out or tripping in; out of the hole, wire-lining and running casing etc. The Driller and his crew must therefore be alert at all times.

The following guidelines provide typical responsibilities and training requirements. The job categories, responsibilities and training requirements may vary slightly from rig to rig and are dependant on the equipment configuration being used.

4.8.1.1 Offshore Installation Manager

The Offshore Installation Manager (OIM) is to ensure that all relevant information is supplied by the Client/Operator to enable hazards to be assessed prior to the well being spudded or worked over. The OIM has the overall responsibility for the safety of the crew, the rig, and damage to the environment.

4.8.1.2 Senior Toolpusher

The Senior Toolpusher is responsible for:

- Ensuring that Company policies and instructions are properly given and to make sure that they are properly understood and implemented.
- Reviewing the Well Program in detail.
- Advising supervisors of any aspects of the prognosis or well plan which might cause the loss of well control.
- Maintaining a system of well control data sheets to be ready for immediate use if required.
- Checking on the adequacy of SBOP/SID training of the relevant personnel on the rig floor and supervisory staff on the drilling rig.

- Ensuring that all operations conducted with equipment associated with pressure control are carried out in a safe and efficient manner.
- Being acquainted with contingency plans relating to, shallow gas, fire, blow-out, pollution and spillage on or around the location.
- Ensuring that all well kick preparations have been made.
- Check the status of the SID functions and alarms, and advise Driller and ROV Operators on requirements for recharging accumulators, based on established guidelines (if applicable).
- Ensuring that the drilling crews have been fully trained in the implementation of the well control procedures for surface BOP operations.
- Ensure riser tensioners are adjusted as required to the correct tension to suit operations.
- Ensure that the toolpushers office control station is manned at all relevant times, with good communications to drill floor.
- All relevant depths and elevations are accurately identified.

4.8.1.3 Chief Engineer or Maintenance Supervisor

The Chief Engineer or Maintenance Supervisor is responsible for:

- Reviewing third party certification for all portable equipment and systems, including data book for SBOP/SID equipment.
- Ensuring all equipment is installed, hooked-up and tested in accordance with applicable standards, rules and regulations.
- Ensuring rig modifications have been performed in accordance with applicable standards, rules and regulations.
- Ensuring that all maintenance procedures are in place and performed by qualified personnel in accordance with Company, Contractor and Equipment Manufacturers recommendations.

4.8.1.4 Subsea Engineer

The Subsea Engineer is responsible for:

- Maintaining all SBOP/SID equipment with assistance from equipment manufacturers representatives if required.
- Ensure all pressure readings are correct, as per manufacturer's recommendations.
- Keep the Senior Toolpusher informed of conditions within his area of responsibility.
- Assist in the proper operation, erection, maintenance, testing, and disconnection of the surface blow-out preventer, SID, and related equipment.

- Assist in the running and retrieving of all tools and equipment.
- Maintain planned maintenance requirements in area of responsibility.
- Assist in preparation of SBOP/SID test reports.
- Assist in ensuring SBOP/SID equipment is operating correctly.
- Check accumulator, manifold pressures and reservoir volumes each tour.
- Check choke manifold and SBOP valve positions each tour.

4.8.1.5 Driller

The responsibilities of the on tour Driller are:

- To shut in the well if a well control situation is observed, as well as activating the Emergency Disconnect Sequence (EDS) as required.
- Responsible for the overall supervision of all drill floor activities and in particular the continuous monitoring of all available indicators in order to detect a kick as early as possible.
- To be aware that since several of the more common causes of kicks can be attributed to human error, he is responsible for the prevention of such kicks by ensuring that he and his crew remain alert at all times and adhere to current practice.

- Ensuring that the choke manifold is properly lined up; that the choke panel is correctly set; that the BOP control system is ready for immediate use, that drill string blow out preventers and crossover subs are cleaned, easily available and counter-balanced if required.
- After closing in a well the driller is responsible for recording, tracking and if necessary controlling pressures.
- The Driller is also responsible for training the floor crew in the following:
    - To understand the importance of detecting and closing in a kick as soon as possible.
    - To recognize the signs of a kick in progress.
    - Where possible, to take appropriate steps to avoid kicks occurring.
    - To ensure that the tasks assigned to each crew member during a close-in and well kill operations are carried out.
    - To understand the hazards involved in all operations and the appropriate precautions to be taken.
- Shut in the well immediately in a kick situation.
- Monitoring pit volumes continuously during all operations for losses or gains. All mud losses or gains shall be recorded and reported to the Senior Toolpusher and Operators representative, giving depths at which they start and stop, rate of loss, or unusual change in rate, also the total volume lost or gained.

- Ensure close communications are maintained between himself, the Mud Loggers, and the Derrickman so that everyone is aware of what is going on at the mud pits. Also to ensure that the mud weight is checked and recorded in accordance with Company policy.
- Ensure correct displacement on trips. It is especially important to check for swabbing on tripping out. The trip tank should be used at all times. Trip tank readings to be recorded on Trip Sheets for all trips. Flow check to be carried out prior to pulling BHA into SID and SBOP.
- Make sure safety valve and proper subs for installing safety valve in all connections are positioned at a convenient spot. When the drill collars reach the rotary, provided they are still through the SBOP, stop and install the proper cross over sub to the safety valve, ensure that the operating key for the valve is at hand.
- At least once per tour whilst drilling take and record the slow circulation pressure (SCP) at slow circulation rate (SCR).
- Ensure SBOP and SID panel is kept clean and free of loose items.
- Check the accumulator and regulated manifold pressures and reservoir fluid level each tour.
- Check the status of the surface and SID accumulators each tour.

- Check for alarms on SID control panel and contact Toolpusher if an alarm is observed.
- Check the choke manifold and SBOP valve positions each tour.
- Check for and report any faults on the electrical control panel(s) i.e. blown bulbs on the function switches, gauge(s) malfunction etc.
- Be aware of the capabilities and any limitations of the SBOP and SID control systems.

THE DRILLER IS THE KEY PERSON IN THE WHOLE OPERATION. THE DRILLER MUST DETECT A KICK AND TAKE THE APPROPRIATE ACTION.

4.8.1.6 Assistant Driller

In many cases the Assistant Driller will act as a "link man" keeping the Driller informed of what is happening throughout the operation and ensuring that the Derrickman has the necessary assistance and guidance in the mud room.

The Assistant Driller aids the Driller by carrying out many of the on tour duties and checks such as:

- Checking choke manifold, valve positions.
- Ensuring that equipment and manifolds are clean and ready to use.
- Checking out mud pumps and manifolds.

- Checks mud systems are lined up properly.
- Fill out sheet of pre-recorded kick data each tour.

4.8.1.7 Derrick Man

The Derrickman is principally involved in the mixing and transferring of mud during a kick. This is a full time job and considerable assistance will be required from the rest of the crew, therefore it is essential that the Assistant Driller and the Mud Engineer are familiar with all aspects of the mud system.

The Derrickman's other responsibilities include:

- If a kick occurs, he should immediately go to the pump room.
- Lining up the de-gasser for use and to pressurize the bulk hoppers, if necessary, as soon as possible after closing in. (During drilling one barite tank should be pressurized at all times.)
- To be aware that during a gas kick a considerable pit volume increase may occur whilst gas is being circulated. He must take into account that weighting up the mud causes an increase in volume and this must be allowed for. A steady, continuous bulk barite supply is needed and therefore careful thought and pre-planning is essential in most systems to ensure that the right fluids are in the right place. A continuous check on

mud weights, especially mud weight going into the hole, must be maintained and any discrepancies immediately notified to the Driller.

4.8.1.8 Floormen

Floormen provide assistance as directed by the Driller, which include:

- Making up or breaking out the top drive.
- Making up or breaking out the circulating head.
- Making up safety valves, inside BOP valves etc.
- Helping at the mud pits.
- Notify Driller of any increase or decrease in mud weight or mud returns.

4.8.1.9 Company Drilling Supervisor

The Company Drilling Supervisor has the overall responsibility for ensuring that the Well Program is adhered to. They are to liaise with the OIM, Senior Toolpusher, and supervisors from the service companies. With regards to drilling with surface BOP, the responsibilities for the Company Drilling Supervisor are no different from a regular drilling operation.

4.8.1.10 Other third party Contractors

In order to provide assistance and support a number of third party contractors or specialists may be assigned responsibilities during SBOP operations. This is particularly the case for initial deployments of SBOP systems. These may be employed by the Company or Drilling Contractor as circumstances dictate.

- SBOP Equipment Vendor Representative
  - Assists in the installation, testing, operation, and maintenance of the SID and the SBOP.
- SBOP/SID Controls Vendor Representative
  - Assists in the installation, testing, operation, and maintenance of the SID acoustic control system.
- Subsea Specialist
  - Responsible for providing advice and for supervising the installation, testing, operation, and maintenance of all the SBOP/SID hardware.
- Project Engineers
  - Responsible for providing advice on all aspects of the SBOP installation and operations and for monitoring the ongoing

operations and trouble shooting operational problems.

- Mud/Data Loggers
  - With regards to the SBOP operations, the Mud/Data Loggers are responsible for the measurement of steel on the ditch magnets at appropriate intervals (initially every 6 hours). Steel accumulating on the ditch magnets is a sign of potential excessive riser or other drill through component wear.

4.8.2 Station Bill

The organization of the crew is part of routine operating procedures. On the Station Bill every person and responsibility during emergency situations is detailed and this should be followed at all drills and emergency situations.

4.8.3 Training

Due to the novel nature of surface BOP operations it is critical that a high level of training, and in particular regular communication, takes place. This needs to be done primarily to ensure that the new operations are performed SAFELY, but also in order to help the efficiency of the operation, which is one of the prime objectives of utilizing a surface BOP in deep water.

Training requirements vary depending on the nature of the operation and the experience of the personnel involved. This section assumes the start-up of a new surface BOP operation on a rig that has no previous experience.

4.8.3.1 Planning Phase

During the planning phase there are many training opportunities for Operator and Contractor staff. This initially starts with shore based managerial and technical staff and develops to include rig based supervisory staff.

Developing a culture that understands of the benefits and limitations of surface BOP technology is a first step. This can be accomplished through planned meetings and workshops such

- Bid clarification meetings
- HAZID workshops
- QRA
- HAZOP workshops
- Well planning meetings
- Pre-spud meetings

At each of these sessions, there is an opportunity to present the SBOP system design, benefits and limitations to a wade range of personnel that are associated with the project in some way.

4.8.3.2 Operations Phase

Prior to and during the initial operation a comprehensive training program should be completed with all senior crew members (Derrickman and above) to familiarize them with the SBOP running and operating procedures, and in particular the Safety procedures. This may be achieved by means of a series of workshops and training sessions at the shore base in the area of operation and onboard the rig.

4.8.3.3 SBOP Specific Training

The following topics are suggested as guidelines for conducting operations phase training sessions and workshops.

- Drilling program
    - Well design
    - Shallow hazards
    - Anticipated problems
    - Well control
    - Pollution prevention
    - Safety
- Introduction to SBOP

  - System overview
  - SOP experience
  - Reasons for SBOP
  - Benefits of SBOP
  - Limitations of SBOP
  - System development
  - System manufacturing and testing
- SID
  - Configuration
  - Specifications
  - Function
- Riser system
  - Configuration
  - Specifications
  - Function
  - Operating limits
- SBOP
  - Configuration
  - Specifications
  - Function
  - Operating limits
- Telescopic joint, tensioners, diverter
  - Configuration
  - Specifications
  - Function
  - Operating limits
- Control Systems
  - SID
  - SBOP
  - ROV

  - Other
- Rig Modifications
  - Equipment installation
  - Handling modifications
  - Tensioner modifications
- Stationkeeping
  - Mooring system or DP system
  - Operating limits and watch circle
  - Loss of station keeping
- Loading, Preparation and testing
  - Heavy lifts
  - Deck storage
  - Component preparation
  - Function testing
  - Pressure testing
- Running procedure
  - SID
  - Riser
  - SBOP
  - Telescopic joint and tensioners
- Retrieval procedure
  - Telescopic joint and tensioners
  - SBOP
  - Riser
  - SID
- Well Control
  - Kick indicators
  - Close in procedures
  - Circulation
  - Hang-off

    - Stripping
    - Bullheading
    - Shearing
- Emergency procedures
    - Loss of station keeping
    - Excessive heel or trim
    - Severe weather
    - Well control
    - Emergency disconnect
    - Riser leak, failure or unplanned disconnect
    - Riser tensioner failure
- Safety
    - Equipment handling
    - Pressure testing
    - Working in moonpool
    - Working with riser tensioners
    - Drills
    - Safety meetings

4.8.3.4 General Training

The rig and shore based personnel should have appropriate training for there normal job positions prior to the implementation of SBOP training. Training requirements include:

Offshore safety and survival
Helicopter underwater escape
Fire-fighting
Emergency response

Rig floor safety

Breathing apparatus

First aid/CPR

Well Control

H2S

Stability

Marine operations

Supervisory skills

Rig specific orientation

Helicopter operations

Crane operations

Fork lift operations

Hazardous materials

Slinging and rigging

GMDSS

On-the-job training

Stuck pipe

Shallow hazards