IADC Deepwater Well Control Guidelines

Well Planning

Well Control Procedures

Equipment

Emergency Response

Training

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FOREWORD

This guide is designed to aid the drilling industry in conducting operations in the deepwater areas of the world. It is based on the experience and study of the contributors who worked on this project. While this manual cannot cover all the problems that may arise, it is intended to give the drilling industry a basis on which to build future deepwater operations. Industry must be aware of the rapidly evolving technology and techniques dealing with deepwater operations.

This document is intended for worldwide use, although many examples are based on the Gulf of Mexico since the operators and contractors active there provided most of the experience and expertise for this project.

In an effort to ensure that these Guidelines continue to evolve as technology and experience advance, the IADC as formed a Revision Committee to review comments from industry. Please submit your comments electronically via the worldwide web at:

http://iadc.org/deepwater.htm

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Chairman's Remarks

I would like to thank the International Association of Drilling Contractors for sponsoring this project. IADC deserves crediting for recognizing the industry's needs regarding deepwater well control, and for enthusiastically supporting this work. I would also like to thank the Offshore Operators Committee for their support of and assistance with this project through the involvement of several of their members.

Much of the success of the Task Force can be attributed to the hard work of the Steering Committee. The members of the Steering Committee gave not only of their time but also unselfishly of their experience and knowledge gained through their years in our industry. Working closely with these individuals has been one of the high points of my industry career. It is with my sincerest thanks that I acknowledge the members of the Steering Committee:

Stanley Christman – Exxon Upstream Development Co.
Curtis Weddle – Cherokee Engineering
Earl Robinson – BHP Petroleum Americas
James Metcalf – Newfield Exploration
Allen Kelly – Diamond Offshore Drilling
Donald Howard – Minerals Management Service, U.S. Dept. of Interior
Adam T. Bourgoyne – Louisiana State University
Steve Kropla – IADC

The five Subcommittee Chairmen must be recognized for their work on this project. They were at the "coal face" in getting the work done.

Marcel Robichaux, Conoco – Well Planning Subcommittee
Mike Briggs, Noble Drilling Company – Well Control Procedures Subcommittee
David Bruce, Diamond Offshore Drilling – Equipment Subcommittee
Donald Shackleford, Halliburton Energy Services – Emergency Response Subcommittee
Richard DeBuys, WCS-Well Control School – Training Subcommittee

Each of the authors and subcommittee members are recognized at the beginning of each chapter. Those Chapters are the true body of this project and it is their contribution that truly requires acknowledgement. Thanks to all of you for your work and dedication to this Task Force.

I would also like to thank Terri Smith, our Technical Writer, for taking our product and organizing it into the coherent work that is presented in this volume.

My thanks to Beverly Wilborn and Kim Meulenberg, my secretaries, for organizing the meetings, preparing my presentations, and keeping me on schedule.

Finally, thanks to my employer, Diamond Offshore Drilling, Inc. and our President, Larry Dickerson, for allowing me the time and resources to work on this project.

M.R. Plaisance
October 1998

Document Map

Deepwater Well Control Guidelines (Guidelines) contains five chapters:

Document structure

1. Well Planning
2. Well Control Procedures
3. Equipment
4. Emergency Response
5. Training

Navigating each chapter

Chapter Beginning

- List of Terms and Definitions (if applicable)
- Table of Contents
- List of Figures (if applicable)
- List of Tables (if applicable)

Chapter Closing

- List of References (all references used in the chapter)
- Index

Cross-references

Cross-references are provided throughout each chapter. These are intended to direct readers to other areas of the *Guidelines* which contain related information.

Example cross-reference:

See also *Well Planning, 1.2, Shallow Water Flow Control Guidelines*

Numbering system

The chapter number precedes all numbered items contained in the chapter, as in the following example items from Chapter 1, Section 2:

Main section	1.2	Figure	1-1
Topic	1.2.1	Table	1-1
Subtopic	1.2.1.1	Page number	1-1
		Index page number	1.1

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CHAPTER 2. WELL CONTROL PROCEDURES

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1.0 WELL PLANNING

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Chapter 1. Well Planning

Well Planning Subcommittee
Marcel Robichaux (Chairman) – Conoco Inc.
John Barker – Vastar Resources, Inc.
Forrest Estep – Transocean
Connie Goers – J. Connor Consulting
Jim Metcalf – Newfield Exploration
John Shaughnessy – Amoco
Charlie Theriot -- Marathon Oil Company

APD	Application for Permit to Drill
BML	Below mudline
COE	Corps of Engineers
DGPS	Differential global positioning system
DOCD	Development Operations Coordination Document
DP	Dynamically positioned
DWOP	Deepwater Operations Plan
ECD	Equivalent circulating density
EPA	Environmental Protection Agency
FPP	Fracture propagation pressure
G&A	Guide and assist
GOM	Gulf of Mexico
GRA	Guidelineless re-entry assist
LCM	Lost circulation material
LMRP	Lower marine riser package
LWD	Logging while drilling
MMS	Minerals Management Service
MODU	Mobile offshore drilling unit
MWA	Military warning area
NPDES	National Pollution Discharge Elimination System
NTL	Notice to Lessees
OBM	Oil-base mud
OCS	Outer continental shelf (Gulf of Mexico)
POE	Plan of Exploration
PWD	Pressure while drilling
RMS	Root-mean-square
SBM	Synthetic-base mud
SWF	Shallow water flow
USCG	United States Coast Guard
WBM	Water-base mud

CHAPTER 1. WELL PLANNING
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1.1 Wellhead & Structural String Design Guidelines

The following topics are covered in this segment:

Key Topic	Related Specific Points
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Operational considerations • conductor and surface casing designs • conductor and surface casing setting depths	– Typical setting depths of deepwater GOM shallow casing strings
Engineering properties • tubulars and connections used for shallow casing string	– Weld-on tubular connector selection considerations – Advertised engineering properties of selected weld-on connectors
Engineering characteristics • selected tubulars • selected drilling equipment	– How to calculate engineering properties of line pipe used in oil wells – Selected line pipe tubular performance properties

1.1.1 Summary

Conservative design approach

The following guidelines are suggested for deepwater wellhead and structural string designs, using the Gulf of Mexico (GOM) as an example. Failures in the design of the structural string and wellhead have proven to be very expensive and a very conservative design approach is encouraged. Sound engineering judgment should be used when determining the worst case used for design purposes. Appropriate safety factors should be included considering the risks and uncertainties in the worst case design assumptions.

1.1.2 Terminology

The following terminology for casing strings will be used since differences between operating companies and geographic regions often exist.

Structural

The first string set is typically 30 in. or 36 in. OD. Since the mid-1980s this casing has generally been installed by jetting to depth with an internal bit or jet head. This string is typically not cemented. A low pressure wellhead housing is installed on the top of this string with a re-entry structure (permanent guide base). Many operators also use a mud mat installed on this string about 14 feet below the wellhead.

Use of mud mat

Recently some operators have omitted the permanent guide base when the mud mat is used with moored rig operations. Typically the mud mat will rest on the mudline. Prior to the 1980s, most deepwater well structural casing was installed by cementing it in a drilled hole using a temporary guide base.

Placement of the jet bit

The structural string can be jetted in the GOM to depths of about 200 feet below the mud line (BML) with few problems related to the placement of the internal jetting bit (relative to the bottom of the structural casing). If more than about 200 feet BML, structural penetration is desired, very careful placement of the jet bit is required along with special procedures such as gel pills and use of mud motors.

Structural string normally installed 200-250 ft BML

While the structural string has been jetted to as much as 320 feet of penetration below the mudline, the normal industry practice is to install about 200-250 feet of structural casing.

Due to its large size this string is generally built to line pipe specifications for wall thickness and grade (API *Specification for Line Pipe)*. Weld-on connectors, either threaded or squnch type, are generally used.

Conductor

In the late 1990s many GOM operators began using a string set 800-1,000 feet below the mudline just above shallow water flow zones. In most cases, this string was hung-off in the structural casing about 80 feet below the low pressure wellhead housing

Conductor typically set at 800-1,000 ft in GOM

The function of this string is to protect the shallow unconsolidated formations while drilling deeper (with or without a riser). This string is typically 20 in. OD and is cemented with special cement developed to mitigate the potential for shallow water flow from behind the string. The use of this string is highly variable from operator to operator depending on the presence of shallow flow potential problems and other operational considerations.

Due to its large size this string is generally also built to line pipe specifications for wall thickness and grade. Weld-on connectors, either threaded or squnch type, are generally used.

Riser and BOP installation

A high pressure wellhead is installed on the top of the conductor string and this is by definition the first string on which the rig's full BOPs and riser are installed. The installation of the riser and BOPs permits deeper drilling with drilling fluid and cuttings returns to the rig.

Surface

This string is usually 13-3/8 or 16 in. O.D. and is set in most deepwater wells at depths of 1,500-3,000 feet below the mudline. If 16 in. OD is used, the string is usually set as a liner due to the wellhead and cementing ECD considerations.

1.1.3 Wellhead Angle

The API RP 16Q establishes a drilling limit of two degrees for the flex joint of a subsea BOP stack. This is interpreted to mean the differential angle between the BOP stack (and structural casing) and the flex joint. Beyond this limit wear in the well and BOPs will be at an unacceptable rate.

Two degree limit may not be suitable for extending drilling time in deepwater

In practice at least one major drilling contractor has found this limit too liberal for extended drilling time in deepwater and that it has led to expensive BOP repairs. This company specifies they will not drill for extended periods if the flex joint/BOP differential angle exceeds one-half degree and/or the wellhead angle exceeds one degree.

Check wellhead wear bushing for wear frequently

Regardless of the angle between the BOPs and the flex joint, it is recommended that the wellhead wear bushing be retrieved and monitored for wear at least every four weeks or sooner if wear indicators are observed.

Tool joint hardbanding

Special attention should be placed on selection of drill string tool joint hardbanding materials as well.

Gyroscopic multishot survey

It is also recommended that a gyroscopic multishot survey of wellhead angle be used for the basis of determining the angle at the wellhead after installation. Relying on bullseye level indicators may not be sufficiently accurate. Some operators run multishot gyroscopic surveys (on 20-30 feet survey intervals) in the structural and drilling riser on a periodic schedule to check the differential angle between the BOPs and the flex joint. Some deepwater operators have used the differential global positioning system (DGPS) to accurately monitor the rig's location over a subsea diverter.

Stiff mooring system

All deepwater operations are especially sensitive to excessive well angles between the BOPs and the flex joint. Maintaining a very stiff mooring system will help prevent excessive rig offsets due to wind, waves and current changes.

Acoustic well positioning

The acoustic well positioning system should also be kept functional and calibrated when drilling in deepwater.

Excessive wellhead and well angle at the mudline can also lead to problems while reconnecting the lower marine riser package (LMRP) after a riser disconnect. The long moment arm created by the tall BOP lower stack (and soft soil just below the mudline), combined with a degree or two of well inclination, can result in very high bending and deflections in the structural string when the LMRP is reconnected (set-down weight).

1.1.4 Structural String Design

High bending and deflections at set-down weight

In a deepwater well the stress levels in the structural string can be significantly higher than the stress level in a shallow water location (even with the same rig type).

Subsea completion, production systems may require higher design loads

Generally the structural string is designed to withstand all calculated loads imparted by the riser to the wellhead during drilling operations. If a well is kept for a future subsea completion from a TLP or other production system, design loads higher than those expected during drilling may be required.

Load sharing between structural and conductor string may not occur

The conservative approach is to select structural casing that has the capacity to maintain material stress within allowable limits when subjected to both bending and axial loading expected while drilling the well (without considering the strength of inner strings). In many cases sharing axial loads between the structural string and conductor string may not be achieved due to possible significant differences in the uncemented length of the two strings. Also, the bending strength contribution of the inner conductor casing is usually relatively small because it is a function of the fourth power of the diameter.

1.1.4.1 Bending and axial loading

Bending and axial loading are the primary considerations in design of the structural casing. The magnitude of bending and axial loads expected will depend on these factors:

Factors Influencing Bending and Axial Loading	
Bend	• Lateral loading at flex joint due to riser loads
	• Wellhead and BOP stickup above the mudline
	• Soil strength below the mudline
	• BOP and wellhead angle (will affect vertical loading and bending)
	• Weight of BOP
Axial loading	• Vertical loading at flex joint due to riser loads
	• BOP weight (buoyed)
	• Wellhead and casing weight (buoyed)

Table 1- 1 Factors influencing bending and axial loading.

Each of these items will be discussed in the following section:

1.1.4.2 Lateral loading

To keep the riser straight and prevent it from buckling, a large vertical axial load is applied at the rig by the riser tensioner system.

Riser tensioner system

The amount of tension that must be pulled is equal to the buoyed weight of the riser, the differential weight between the mud in the riser and seawater and some amount of overpull at the top of the BOP stack.

Axial overpull

The axial overpull at the top of the BOPs is transmitted through the flex joint and into the LMRP at the top of the BOP stack. The flex joint permits bending at angles to about ten degrees between the riser and the top of the BOPs.

If the wellhead were perfectly vertical and the flex joint angle were zero, only a vertical tension component and no horizontal component would be introduced to the top of the BOPs. This never occurs on a deepwater rig and a significant horizontal load will be introduced at the flex joint during special situations such as during an emergency disconnect with a dynamic positioned rig or a mooring failure on a moored rig.

Since most deepwater wells may be re-entered at a future date with a different type rig, both moored and dynamic positioned operations should be considered when developing the design worst case.

Tension at the flex joint

The amount of tension desired at the flex joint will depend on the type of rig and the characteristics of the LMRP connector. For example, a connector will disconnect only when the axial load is above a certain value and the bending moment is below a certain value.

DP rig emergency riser disconnect

For a dynamic positioned rig emergency riser disconnect, operations must be complete before the following conditions occur:

1. the load and bending limits of the LMRP connector are reached; and
2. the angle and stroke of the telescopic joint are reached.

A minimum axial load is required to permit the LMRP connector to lift-off the lower BOPs. Estimates of worst case lateral loads can be obtained from a riser analysis and/or a riser disconnect analysis which considers these rig related issues.

As a lower flex joint bends due to lateral loading, a moment and a shear force are introduced as the elastomer in the flex joint strains. These loads should be included in the structural casing design.

A flex joint typically accommodates angles up to 10 degrees on either side of its axial center and can have a

stiffness of about 20-25 kip-ft per degree of angle change and a shear load of 3-5 kips (depending on flex joint angle). During a design environment, such as during an emergency disconnect, the structural casing and BOPs may deflect several degrees, depending on soil and casing stiffness. The moment introduced from the flex joint is the difference between the lower flex joint angle and the structural/BOP angle times the flex joint stiffness.

1.1.4.3 Wellhead and BOP stickup

The total height from the mudline to the flex joint has a large impact on the amount of bending imparted to the structural casing. Typically, the low pressure wellhead housing is located about 14 ft above the visible mudline to insure ROV access and camera visibility even with some cuttings build-up.

Flex joint height

Typically the BOP stack is about 50 ft tall from the lower wellhead connector to the flex joint. This results in a total moment arm of 64 ft from the flex joint to the visible mudline.

Flex joint distance to LMRP

The distance from the flex joint to the LMRP connector is highly variable from rig to rig and will have an impact on the bending moment expected at this connector. As discussed above, an LMRP connector will disconnect only when the combined bending moment and axial load are within certain limits.

1.1.4.4 Soil strength below the mudline

If the soil just below the mudline were extremely strong (such as granite), the wellhead and BOP stick up distance would be all that is needed to calculate the bending stress in the structural casing (at the mudline). A simple cantilever beam equation could be used to model stress resulting from the horizontal load at the flex joint and stick-up length. However, deepwater soil strengths are very low and gradually increase in strength with depth .

Bit set-down test

In many cases, a site specific soil boring is obtained and used for structural casing design. When a soil boring is not performed, it is possible to get a better understanding of the shallow below mudline soil strength by performing a "bit set-down test". From experience, it is known that a 26 inch bit with 5,000 lb set-down weight (with pumps off) will stop penetrating below the mudline when soil strength is approximately 150 lb/ft.

Generally soft clays found near the mudline in deepwater will behave as a plastic material when a pile is subject to static or cyclic lateral loading.

Behavior of soft clay near mudline

As the structural string is laterally loaded, it will deflect as the soil develops more resistance and the pipe increases its bending stress. A cavity will form on the side of the pile as soil is displaced away from the pile in the direction of loading. Subsequent cycle loads may then result in increased bending loads as the pile moves through the slack zone created by a previous loading. If excessive deflections occur, wear of casing strings just below and in the subsea wellhead will occur. Figure 1-1 on the following page reflects typical GOM soil shear strengths.

The lateral resistance of a pile does not increase in simple proportion to loading. The problem is then how to relate the soil resistance to the string deflection in a cyclic loading condition.

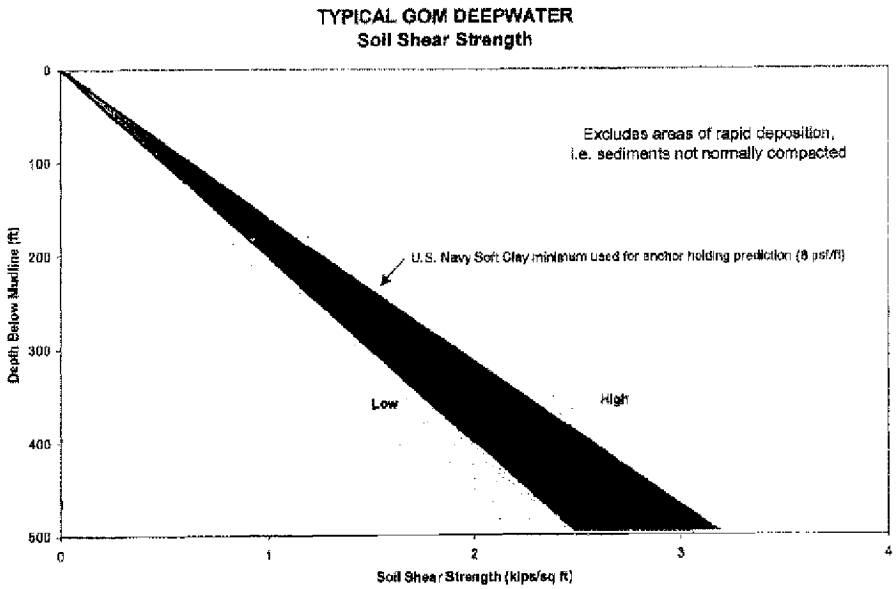


Figure 1-1 Typical GOM deepwater soil shear strength.

Modeling soil resistance to lateral loads and bending

To accurately model the casing bending and soil interface problem, a computer program is needed. Many are commercially available. The computer programs generally model the soil resistance to lateral loads and bending as a series of nonlinear springs. Figure 1-2 below shows typical bending loading calculated for a GOM deepwater structural string.

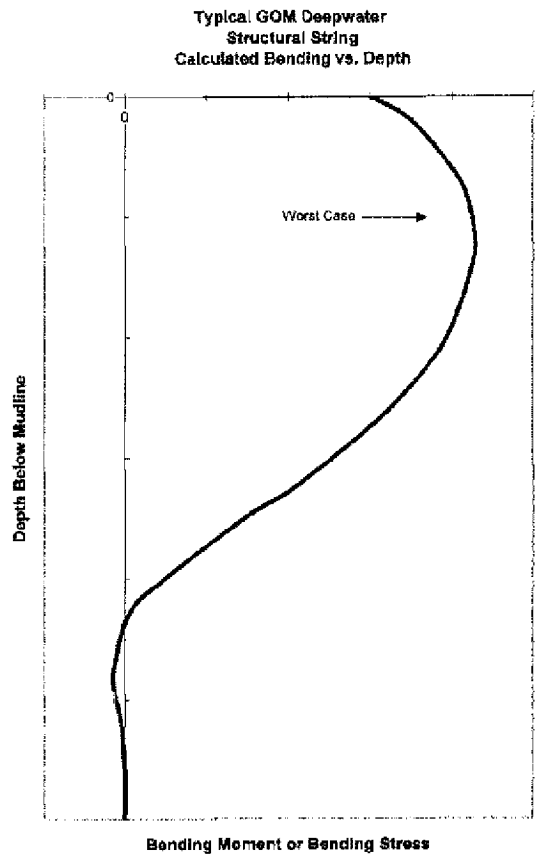


Figure 1-2 Typical GOM deepwater structural string: calculated bending vs depth.

1.1.4.5 Axial loading

Vertical loading

The total loading or stress in the structural string is composed of stress due to bending and axial stresses. Axial stresses are the result of riser tension less BOP buoyed weight, subsea wellhead buoyed weight and buoyed casing weight (conductor or surface).

1.1.5 Wellhead and Structural String Design Guidelines

The axial capacity of the structural casing can be estimated by assuming that the skin friction (adhesion) is equal to the shear strength of the soil and integrating along the length. End bearing is not included. The equation is:

EQUATION: Estimating the axial capacity of the structural casing

$$Q = b * \pi * OD * f_o^z \, cdz)$$

Where:

Q = axial capacity of the structural casing, kips

b = reduction factor which depends on the disturbance during jetting

OD = outside diameter of the structural casing, ft

z = length of structural casing below the mudline, ft

c = soil shear strength, kip/ft ^{2}

The reduction factor *b* will depend on the disturbance during the installation of the structural casing. If the casing was jetted in place, the reduction factor may be as low as 0.25 (Beck and Jackson, 1991). If care is taken during jetting to minimize soil disturbance, *b* may be as high as 0.50. With time after installation *b* should increase and approach unity after several weeks.

Mud mats are commonly used in GOM operations and are typically installed about fourteen feet below the low pressure wellhead housing.

Mud mats in the GOM

EQUATION: Mud mat support capacity

The support capacity of a mud mat can be calculated with this equation:

Q = footprint area of mud mat - ft^2 - SS* 2.5 (approximate)

Where:

Q = mudmat support capacity, kips

SS = soil strength - lb/ft^2 (typical value for GOM about 75 lb/ft^2)

Mud mat dimensions and axial capacity

A 16 ft by 16 ft square mud mat can be expected to provide about 50 kips of axial capacity while a 10 ft by 12 ft mud mat will give only about 20 kips of capacity.

Many operators use mud mats more as a positive indicator of when to stop jetting the structural casing (when the mud mat hits the mudline) than as an axial load carrying member.

Mud mats with templates and tight well spacing

Mud mats are usually very large and can interfere with placement of adjacent wells if a template or tight mudline well spacing is planned. Generally, mud mats are not retrievable without recovery of the wellhead and structural casing.

1.1.6 Design Criteria

A structural string can be thought of as a pile similar to those used on a steel jacketed platform. Recommendations made in API RP 2A for design of fixed offshore platforms pile foundations should be used for structural casing (API Recommended Practice 2A).

The above mentioned RP includes recommended procedures for both axially loaded piles and piles subject to lateral loading. Static and cyclic loading cases with an appropriate safety factor should be included in the design analysis.

API RP 2A: structural member design

API RP 2A recommends that structural members (including piles) be designed considering both bending and axial stresses. This criteria is considered more rigorous than just considering bending stresses in a structural string.

The following equation is recommended by the API and AISC Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings:

EQUATION: Design, Fabrication, and Erection of Structural Steel for Buildings

$$f_a/(F_s*F_y) + f_b/(F_s*F_y) \leq 1.0$$

Where:

f_a = computed axial stress, psi

f_b = computed bending stress, psi

F_y = yield stress of steel, psi

F_s = factor of safety, recommend a 0.8 for axial tension and 0.9 for bending

The depth below mudline at which the combined stresses are at a maximum are usually located at the maximum bending moment.

With the bending moment for the design worst case calculated, the stress in the structural casing due to bending can be calculated:

EQUATION: stress in structural casing due to bending

$$f_b = (M * OD*6) / I$$

Where:

f_b = bending stress, psi

M = bending moment, ft-lb.

OD = outside diameter of the tube, in.

I = moment of inertia of the tube, in^4 = $(\pi/64)*(OD^4-ID^4)$

ID = nominal inside diameter, in.

With the axial load calculated, the axial stress in the structural casing due to the axial load can be calculated:

EQUATION:
axial stress in structural casing due to axial load

$$f_a = P_a/A$$

Where:

f_a = axial stress in the tube, psi

P_a = axial load in casing, lb.

A = cross sectional area of the tube (nominal ID), in^2

1.1.6.1 Engineering Properties of Line Pipe

Burst

Using the Barlow equation found in API Specification 5C3, the burst of a tube is dependent on the wall thickness, wall thickness tolerance, yield strength and diameter of the tube (API Bulletin 5C3). For casing API Specification 5CT allows a 12.5% wall thickness tolerance.

The wall thickness tolerance specified in API Specification 5L for line pipe is dependent on the size of the pipe, type manufacture (seamless or welded) and grade. For 20 in. and larger line pipe, the API wall thickness tolerance is:

API Line Pipe Tolerances		
Outside diameter and type of pipe	Wall thickness tolerance, percent	
	Grade A, B, A25	Grade X42 to X80
20 in and larger, welded	-10	-8
20 in and larger, seamless	-12.5	-10

Table 1- 2 API Line Pipe Tolerances

API Specification 5L specifies the tensile requirements for line pipe (yield and ultimate strength). The standard line pipe grades and yield strengths are:

API Line Pipe Grades	
Grade	Yield Strength (psi)
A25	25,000
A	30,000
B	35,000
X42	42,000
X46	46,000
X52	52,000
X56	56,000
X60	60,000
X65	65,000
X70	70,000
X80	80,000

Table 1- 3 API Line Pipe Grades

There are other differences between the manufacturing specifications for casing and line pipe. For example, API casing specifications for 80 grade material has hardness specifications while line pipe does not. It is generally recommended not to weld on casing while line pipe generally has welded connections. Welding procedures and requirements for higher grade line pipe (>grade B) are very demanding and require special engineering controls.

Like casing, line pipe is manufactured in standard outside diameters and wall thicknesses. Table 1- 4 on the following page includes selected standard line pipe dimensions included in API Specification 5L and some non-API dimensions.

Since line pipe is manufactured to a different specification than casing, the tube is referenced by a different weight per foot than casing (even for the same wall thickness as casing).

Size OD in.	Wall Thickness in.	Plain End Weight lbs. / ft.
16	0.500	82.77
	0.562	92.66
	0.625	102.63
	0.688	112.51
	0.750	122.15
	0.812	131.71
	0.875	141.34
	0.938	150.89
	1.000	160.20
	1.062	169.43
	1.250	178.72
	1.188	187.93
	1.250	196.91
18	0.500	93.45
	0.562	104.67
	0.625	115.98
	0.688	127.21
	0.750	138.17
	0.812	149.06
	0.875	160.33
	0.938	170.92
	1.000	181.56
	1.062	192.11
	1.125	202.75
	1.188	213.31
	1.250	223.61
18.6	0.500	96.79
	0.625	120.15
20	0.500	104.13
	0.562	116.67
	0.625	129.33
	0.688	141.90
	0.750	154.19
	0.812	166.40
	0.875	178.82
	0.938	190.96
	1.000	202.92
	1.062	214.80
	1.125	226.78
	1.188	238.68
	1.250	250.31
	1.312	261.86
	1.375	273.51

Size OD in.	Wall Thickness in.	Plain End Weight lbs. / ft.
22	0.500	114.81
	0.562	128.67
	0.625	142.68
	0.688	156.60
	0.750	170.21
	0.812	183.75
	0.875	197.41
	0.938	211.00
	1.000	224.28
	1.062	237.48
	1.125	250.81
	1.188	264.06
	1.250	277.01
	1.312	289.88
	1.375	302.88
	1.438	315.79
	1.500	328.41
24	0.500	125.49
	0.562	140.68
	0.625	156.03
	0.688	171.29
	0.750	186.23
	0.812	201.90
	0.875	216.10
	0.938	231.03
	1.000	245.64
	1.062	260.17
	1.125	274.84
	1.188	289.44
	1.250	303.71
	1.312	317.91
	1.375	332.25
	1.438	346.50
	1.500	360.45
	1.562	374.31
26	0.500	136.17
	0.562	152.68
	0.625	169.38
	0.688	185.99
	0.750	202.25
	0.812	218.43
	0.875	234.79
	0.938	251.07
	1.000	267.00
	1.250	330.42

Size OD in.	Wall Thickness in.	Plain End Weight lbs. / ft.
28	0.500	146.85
	0.562	164.69
	0.625	182.73
	0.688	200.68
	0.750	218.27
	0.812	235.78
	0.875	253.48
	0.938	271.10
	1.000	288.36
30	0.750	234.29
	0.812	253.12
	0.875	272.17
	0.938	291.14
	1.000	309.72
	1.062	328.22
	1.125	346.93
	1.188	365.56
	1.250	383.81
	1.500	456.57
	1.750	528.00
32	0.750	250.31
	0.812	270.47
	0.875	290.86
	0.938	311.17
	1.000	331.08
	1.062	350.90
	1.125	370.96
	1.188	390.94
	1.250	410.51
34	0.750	266.33
	0.812	287.81
	0.875	309.55
	0.938	331.21
	1.000	352.44
	1.062	373.59
	1.125	394.99
	1.188	416.31
	1.250	437.21

Size OD in.	Wall Thickness in.	Plain End Weight lbs. / ft.
36	0.750	282.35
	0.812	305.16
	0.875	328.24
	0.938	351.25
	1.000	373.80
	1.062	396.27
	1.125	419.02
	1.188	441.69
	1.250	463.91
	1.500	552.70
	1.750	640.14
	2.000	726.25
38	0.750	298.37
	0.812	322.50
	0.875	346.93
	0.938	371.28
	1.000	395.16
	1.062	418.96
	1.125	443.05
	1.188	467.06
	1.250	490.61
40	1.000	416.52
	1.062	441.64
	1.125	467.08
	1.188	492.44
42	1.000	437.88
	1.062	464.32
	1.125	491.11
	1.188	517.82
	1.250	544.02
	1.500	648.82
	1.750	752.28
	2.000	854.41
48	1.000	501.96
	1.062	532.38
	1.125	563.20
	1.188	593.94
	1.250	624.12
	1.500	744.94
	1.750	864.42
	2.000	982.57
	2.500	1214.86

Table 1-4 Selected standard and non-API line pipe dimensions.

The following example shows how to calculate the minimum internal yield pressure (burst) for 20 in. seamless line pipe with a 0.625 in. wall thickness (129.33 lbs/ft) and a X56 grade:

EQUATION: minimum internal yield pressure for 20 in. seamless line pipe, 129.33 lb/ft, X56

$P_i = T*[2*Yp*t/OD]$

Where:

P_i = minimum internal pressure (burst) - psi

T = minimum wall thickness tolerance reduction factor

Yp = minimum yield strength - psi

t = nominal wall thickness - in.

OD - outside diameter - in.

For 20 in. 129.33 lbs/ft X56 grade with 0.625 in. wall (seamless):

$P_i = 0.90*[2*56000*0.625/20]$

P_i = 3150 psi (welded pipe would have a T = 0.92 and a P_i = 3220 psi)

Collapse

Collapse rating of line pipe can be calculated from equations included in API Bulletin 5C3. Most line pipe used in oil wells is large OD with large wall thickness. The OD/t ratio is usually high and the casing is usually in an elastic collapse or transition collapse region of applicability.

Elastic collapse and transition collapse

Thinner wall (higher OD/t) line pipe that falls in the elastic collapse pressure region will have a collapse rating which is not dependent on the minimum yield strength of the steel. Ovality of large line pipe in the elastic collapse

pressure region is also a critical factor. The line pipe should be checked for ovality or the collapse rating of the pipe reduced due to the ovality.

Ovality is a critical factor

All collapse ratings should also be adjusted due to axial tension which will impact the applicable collapse region of line pipe. The collapse rating of a tube is normally calculated based on the nominal wall thickness of the tube.

Tension/Compression

The pipe body strength of line pipe is normally calculated by the product of the nominal pipe body cross-sectional area and the minimum yield strength of the steel. The compression rating of a tube is assumed to be the same as in tension. Nominal wall thickness rather than minimum wall thickness is generally used to calculate line pipe tension/compression ratings.

Bending

For structural casing, bending is a primary design consideration. The bending yield strength of a circular tube can be calculated with this equation:

EQUATION: bending yield strength of a circular tube

Bending rating, ft-lbs = $[(Y * I) / (OD/2)] / 12$

where:

Y = yield strength of the tube, psi

OD = outside diameter of the tube, in.

I = moment of inertia, in^4 $(\pi/64)*(OD^4-ID^4)$

ID = inside diameter, in.

For example, a 30 in. OD tube with a 1.5 in. wall thickness and X52 grade would have a 3.95 million ft-lbs bending yield strength (assuming no axial stresses). Table 1-5 below includes the calculated bending yield strengths of line pipe commonly used in structural strings.

			Grade B				Grade X42				Grade X52				Grade X56			
Size OD in.	Wall Thickness in.	Weight / foot lbs/ft	Bending 10^6 ft-lbs	Axial strength 10^6 lbs	Burst (welded) psi	Collapse psi	Bending 10^6 ft-lbs	Axial strength 10^6 lbs	Burst (welded) psi	Collapse psi	Bending 10^6 ft-lbs	Axial strength 10^6 lbs	Burst (welded) psi	Collapse psi	Bending 10^6 ft-lbs	Axial strength 10^6 lbs	Burst (welded) psi	Collapse psi
20"	0.500	104.13	0.425	1.372	1676	745	0.510	1.286	1932	767	0.631	1.593	2392	772	0.680	1.715	2576	772
	0.625	129.33	0.521	1.332	1969	1209	0.625	1.598	2415	1304	0.774	1.978	2990	1415	0.834	2.131	3220	1450
	0.750	154.19	0.614	1.586	2363	1714	0.736	1.905	2898	1844	0.912	2.359	3588	2064	0.982	2.540	3864	2140
	0.812	166.40	0.658	1.713	2558	2033	0.790	2.056	3138	2229	0.978	2.546	3885	2447	1.053	2.741	4183	2514
	1.000	202.92	0.788	2.089	3150	2999	0.945	2.507	3864	3396	1.170	3.104	4784	3904	1.260	3.343	5152	4089
24"	0.500	125.49	0.620	1.292	1313	443	0.744	1550	1610	443	0.921	1920	1993	443	0.991	2.067	2147	443
	0.625	156.03	0.762	1.606	1641	822	0.915	1928	2013	857	1.133	2387	2492	874	1.220	2.570	2683	874
	0.750	186.23	0.901	1.917	1969	1209	1.081	2301	2415	1304	1.338	2849	2990	1415	1.443	3.068	3220	1449
	0.812	201.09	0.967	2.070	2132	1401	1.161	2484	2615	1528	1.437	3076	3237	1807	1.548	3.313	3486	1737
	1.000	245.64	1.164	2.529	2625	2142	1.396	3038	3220	2351	1.729	3757	3987	2612	1.862	4.046	4293	2692
26"	0.500	135.70	0.731	1.402	1212	347	0.877	1682	1485	347	1.086	2083	1840	347	1.169	2.243	1982	347
	0.625	169.38	0.900	1.744	1514	674	1.080	2093	1858	685	1.338	2591	2300	685	1.440	2.790	2477	685
	0.750	202.25	1.065	2.082	1817	1031	1.278	2499	2229	1098	1.582	3094	2760	1185	1.704	3.332	2972	1182
	0.812	218.43	1.144	2.249	1968	1207	1.373	2699	2414	1303	1.700	3341	2988	1413	1.831	3.596	3216	1447
	1.000	267.00	1.379	2.749	2423	1613	1.655	3299	2872	1864	2.049	4084	3550	2163	2.206	4.398	3963	2252
	1.250	330.41	1.674	3.402	3022	2801	2.009	4082	3716	3157	2.487	5054	4600	3906	2.678	5.443	4954	3787
30"	1.000	309.72	1.855	3.169	2100	1364	2.227	3.827	2576	1153	2.770	4.738	3189	1630	2.983	5.102	3435	1680
	1.250	383.81	2.272	3.952	2625	2142	2.727	4.742	3220	2361	3.376	5.871	3987	2612	3.638	6.322	4293	2692
	1.500	456.57	2.658	4.701	3150	2999	3.191	5.641	3864	3396	3.950	6.984	4784	3904	4.254	7.521	5152	4089
	1.750	528.00	3.024	5.437	3675	3845	3.628	6.524	4508	4430	4.493	8.077	5581	5196	4.835	8.698	6011	5486
36"	1.000	373.80	2.730	3.848	1750	951	3.277	4.619	2147	1006	4.057	5.718	2658	1064	4.369	6.158	2862	1093
	1.250	463.91	3.342	4.776	2188	1497	4.010	5.731	2683	1503	4.966	7.096	3322	1775	5.347	7.642	3578	1836
	1.500	552.70	3.927	5.690	2625	2142	4.712	6.829	3220	2361	5.834	8.454	3987	2612	6.283	9.104	4293	2692
	1.750	640.14	4.486	6.591	3063	2855	5.383	7.909	3757	3273	6.664	9.793	4651	3889	7.177	10.546	5009	3857
	2.000	726.24	5.019	7.478	3500	3670	6.023	8.973	4293	4065	7.457	11.11	5316	4766	8.031	11.964	5724	5021

Table 1- 5 Selected line pipe performance properties.

1.1.6.2 Weld-on connectors

Connectors are usually welded on line pipe and can either be squnch joint or threaded types. Almost all weld-on connectors use resilient seals rather than metal to metal seals for connection sealing.

Squnch joint type connectors

Generally, squnch joint type connectors have looser manufacturing tolerances and as a result, have lower ratings in bending and internal pressure.

Some connectors are available in a range of steel yield strengths which will impact the rating of the connector.

Many commercially available connectors have a bending rating and a burst rating less than the line pipe tube to which they are welded.

A well engineered design will result in the proper combination of line pipe and connector mechanical pipe strength. Table 1-6 on the following page lists the engineering characteristics of several commercially available weld-on line pipe connectors. Note that the rated performance properties of a connector must be decreased if it is subject to combined loading, i.e., concurrent axial tension and bending.

All connector properties listed in Table 1-6 are specified in the respective manufacturers' catalogues.

Size / Manufacturer	Model	Wall thickness in.	Manufacturer's Rated (1) Bending 10^6 ft-lbs	Tension 10^6 lbs	Pressure psi	Type	Remarks
36"							
XL Systems	XLW	1.5	6.732	9.775	(2)	Threaded	Full bore ID
XL Systems	XLC-HS	1.5	6.732	9.775	(2)	Threaded	Flush OD & ID
Dril Quip	D-90 MT	1.5	6.660	6.150	7500	Threaded	Flush OD
Dril Quip	H-90 MT	1.5	6.010	5.260	6000	Threaded	
XL Systems	XLC	1.5	5.257	7.669	(2)	Threaded	Flush OD & ID
Vetco	RL-4RB	1.5	5.250	10.000	3900	Threaded	
Vetco	ALT-2	1.5	5.050	7.320	5050	Squnch	
Dril Quip	D-60 MT	1.5	4.440	4.100	5000	Threaded	Flush OD
Dril Quip	HD-90	1.5	4.040	4.730	1500	Squnch	
Dril Quip	H-60 MT	1.5	4.010	3.510	5200	Threaded	
Dril Quip	HF-90	1.5	3.670	4.210	1500	Squnch	Full bore
Dril Quip	FOD-90	1.5	3.600	4.670	1500	Squnch	Flush OD
Dril Quip	NF-60	1.5	2.450	2.800	1500	Squnch	Full bore
30"							
XL Systems	XLW	1.5	4.558	8.058	(2)	Threaded	Full bore ID
Dril Quip	H-90 MT/QT	1.5	4.380	4.440	6700	Threaded	
Vetco	ALT-2	1.5	4.200	6.200	3000	Squnch	
Vetco	RL-4	1.5	3.800	6.240	5000	Threaded	
Vetco	RL-4RB	1.5	3.800	6.240	5000	Threaded	Near flush OD
Dril Quip	D-90 MT	1.5	3.660	3.990	9300	Threaded	Near flush OD
XL Systems	XLC	1.5	3.539	6.348	(2)	Threaded	Flush OD & ID
Dril Quip	HD-90	1.5	2.970	4.220	1500	Squnch	
Dril Quip	H-60 MT/QT	1.5	2.890	2.930	6200	Threaded	
Dril Quip	D-60 MT	1.5	2.440	4.560	6200	Threaded	Near flush OD
Dril Quip	NS-60	1.5	1.760	2.500	1500	Squnch	
20"							
Dril Quip	H-90 MT/QT	0.812	1.830	2.850	7800	Threaded	
Vetco	RL-4S	0.812	1.560	2.440	7500	Threaded	
Vetco	RL-1S	0.812	1.560	2.440	7500	Threaded	Reduced OD from RL-4S
XL Systems	XLW	0.812	1.222	3.182	(2)	Threaded	Full bore ID
Dril Quip	HD-90	0.812	1.060	2.250	3000	Squnch	
Dril Quip	S-60 MT/QT	0.812	0.930	1.450	5200	Threaded	
Hunting	Boss	0.812	0.885		6480	Threaded	Thread and coupled
XL Systems	XLF	0.812	0.652	1.630	(2)	Threaded	Flush OD & ID
Dril Quip	H-90 MT/QT	0.625	1.830	2.850	6075	Threaded	
Dril Quip	H-60 MT/QT	0.625	1.220	1.900	4050	Threaded	
Vetco	ALT-2	0.625	1.120	2.430	5000	Squnch	
XL Systems	XLW	0.625	0.968	2.473	(2)	Threaded	Full bore ID
Dril Quip	S-60 MT/QT	0.625	0.930	1.450	4050	Threaded	
Vetco	LS	0.625	0.917	2.090	3600	Threaded	
Dril Quip	FB-60 MT/QT	0.625	0.900	1.410	4050	Threaded	Full bore ID
Vetco	RL-4S	0.625	0.850	1.500	4100	Threaded	
Vetco	RL-1S	0.625	0.850	1.500	4100	Threaded	Reduced OD from RL-4S
Vetco	RL-4C	0.625	0.802	1.464	3600	Threaded	Reduced OD from RL-4S
Dril Quip	NS-60	0.625	0.710	1.500	3000	Squnch	
Dril Quip	E-60 MT/QT	0.625	0.700	1.200	4050	Threaded	
XL Systems	XLF	0.625	0.527	1.305	(2)	Threaded	Flush OD & ID

Note: (1) Capacity at yield of connector under single load conditions, no safety factor included
(2) Advertised at 100% burst of pipe body

Table 1-6 Selected large connector engineering properties.

Safety factor and connector properties

It is also recommended that a safety factor be applied to the connector's properties since it is not recommended to stress a connector in service all the way to its yield strength. Without a safety factor the only safety margin is due to the connector's ultimate strength being greater than its yield strength.

1.1.6.3 Subsea wellheads and wellhead connectors

Standard subsea wellheads are rated between 2.5 and 3.0 million ft-lbs in bending and as much as seven million lbs in tension. Most subsea wellhead manufacturers offer wellhead systems with higher bending ratings.

For most wellhead systems, bending loads are governed by wall thickness of the high pressure housing at the connection to the BOPs and the design of how the high and low pressure wellheads interact together. Typically the standard wellhead system will have a high pressure housing OD of about 27 in.

Obtaining higher bending

To obtain the higher bending, the high pressure housing OD is increased (to as much as 30 in.) and the high pressure to low pressure wellhead housing interface is strengthened.

Deepwater bending rating

Bending rating has been increased to as much as seven million ft-lbs for very deepwater applications. Most wellhead manufacturers also offer provisions that will rigidly lock the high pressure housing to the low pressure housing. This is done to mitigate the affect of fatigue on the surface casing (just under the high pressure housing) due to vortex induced vibration caused by high currents impacting the drilling riser.

The bending strength of wellhead connectors depends upon the axial load and the internal pressure. Most standard wellhead connectors are limited in bending strength to 3000-4000 kip-ft. Several vendors offer connectors rated for higher bending loads, including one rated to seven million ft-lbs in bending.

1.1.7 Conductor Casing Considerations

Conductor casing is generally run in open water before the BOPs and riser are installed. As an added factor of safety, it is common practice for the top 200-300 ft of the conductor casing to have an increased bending strength to accommodate running stresses and to help share bending with the structural string.

Washing-down conductor string

If it becomes necessary to wash-down the conductor casing to land the string in the low pressure housing, the axial stress in the string above the subsea wellhead should always be positive (upward force) to keep the casing above the wellhead (in the seawater) from buckling.

1.1.8 Top Hole Casing Points

1.1.8.1 Structural casing setting depths

Overview

This is the first string of casing run. It is usually 30" or 36". The objective of the casing is to provide support for future loads to be applied; particularly the weight of the 20" which must be supported until the cement can provide additional support.

The casing is run with the guidebase and mud mat. The length to run is set prior to any drilling on the seafloor. It is usually pushed into the seafloor by its weight and the running string while a mud motor circulates out soil from inside the casing. The length to run can be determined by soil borings or area experience.

Setting a short length may not support the required loads and getting a longer length to the proper depth may be difficult. When running a longer length, it is necessary to do excessive reciprocation, and the soil strength may be damaged. The holding capability of damaged soil is an unknown.

The following important points are discussed in detail below:

- Load bearing capacity
- Bending load rating
- Drill ahead tools
- Jetting casing
- Connectors

1.1.8.2 Load bearing capacity

The load bearing capacity can be calculated assuming the strength of 80 psf (lbs per square foot) at the mud line and the capacity increases 10 psf each foot of penetration.

EQUATIONS:
Load bearing capacity examples

Example 1:

200' of 30" conductor is set below the mud line.

Area of Pipe circumference:

$2 \pi r L = 2 * \pi*(30/2)/12*200' = 1{,}571$ sq feet

$$\text{Bearing} = \frac{80 \text{ psf} + (200*(10) + 80)}{2} = 1{,}080 \text{ psf}$$

Thus:

Load Capacity = 1,571 sq feet * 1,080 psf = 1,696,700 lbs

Example 2:

150' of 36" conductor is set below the mud line.

Area of Pipe circumference:

$2 \pi r L = 2 * \pi *(36/2)/12*150' = 1{,}414$ sq feet

$$\text{Bearing} = \frac{80 \text{ psf} + (150*(10) + 80)}{2} = 830 \text{ psf}$$

Thus:

Load Capacity = 1,414 sq feet * 830 psf = 1, 173,620 lbs

1.1.8.3 Bending load rating

Bending load rating is the stiffness of the conductor casing. This assumes the casing is set deep enough below the mud line to be rigidly fixed. The following are sample calculations:

Bending Load compares to Bending Stress = 90% of Yield

$$\text{Bending Stress} = \frac{M*Y}{I}$$

Where:

M = Bending moment, ft-lbs

Y = Radius of tube

I = Moment of Inertia

$I = \pi (OD^4 - ID^4)/64$

Example 1

The Rating of 30", 1 inch wall, 60 ksi pipe is as follows:

$$M = \frac{\text{Bending Stress} * I}{Y}$$

$$\frac{60 \text{ ksi} * 0.90 * \pi(2.5^4 - 2.33^4)/64}{2.5/2 \text{ ft}} = \frac{54{,}000 \text{ lbs/in}^2 * 0.47074 \text{ ft}^4}{1.25 \text{ ft}}$$

= 2,928,000 ft-lbs

Example 2:

36", 1-3/4-in wall, 60 ksi pipe:

$$\frac{60 \text{ ksi} * 0.90 * \pi (3^4 - 2.708^4)/64}{3/2 \text{ ft}} = \frac{54{,}000 \text{ lbs/in}^2 * 1.336 \text{ ft}^4}{1.5 \text{ ft}}$$

= 6,928,000 ft-lbs

Weight of the 20" Casing: The casing is usually 169#/ft (0.812" wall) or 129#/ft (0.625" wall). A 1,500' string of casing would weigh 195,000 lbs in air or 170,000 lbs in seawater.

Drill Ahead Tools

Drill ahead tools are designed to allow the drill string to be released from the structural pipe running tools once it has reached the desired setting depth. The bit and BHA can then be used to drill ahead. This eliminates a round trip to the surface. The tools are often cam-actuated.

Jetting casing

At least one operator used to jet the structural casing into place by use of a circulating jet head and large "doughnut" weight rings. The doughnuts and BHA simulated the weight of the 20" to be hung off in the structural casing. Thus, if the casing held the doughnuts it could be expected to safely support the 20".

The disadvantages of this method were the difficulty handling the doughnuts and the hole could not be drilled ahead without tripping for a drilling assembly.

1.1.8.4 Connectors

Generally a threaded connection is welded on to the tube. The connector is designed to exceed the capacity of the tube. The connectors have a flush OD so that they do not interfere with jetting and disturb bearing capacity.

Flush OD, internal upset

The connectors are internally upset. That is necessary to have the required bending strength.

The connectors are non-cross threadable to eliminate the need for spares of the big pipe on board. They have minimum turn make up (one vendor takes 5/8 turn). This

makes the pipe easier to make up and minimizes the amount of equipment needed to run it.

Casing installed box up/pin down

The casing is usually box up/pin down. Anti-rotation keys are installed after make up. The casing usually has pad eyes for handling and running that have to be cut off at the rotary.

Casing can be run with a handling tool (similar to a safety clamp) for side door elevators to shoulder out on. The industry has moved away from a squnch type connector that was run pin up/box down because the quick stab had a lock ring that was not pre-loaded. Motion was possible box-to-pin due to the lock ring. Thus, fatigue was a problem.

Casing is not welded as is done with jack-up drive pipe because of the difficulty welding on a floating (moving) rig and the fact that connectors are more cost effective.

1.1.9 Conductor Setting Depth (20")

Overview

Drilling riserless with returns to the seafloor

This hole section is drilled riserless with returns to the seafloor. Traditionally, the setting depth was chosen prior to beginning drilling and was chosen to be above any formation that could contain hydrocarbons or require any mud weight. The goal was to get casing to a depth where the fracture gradient would allow increasing the mud weight once the subsea BOP and marine riser were run.

Drilling with mud allows deeper casing point

Drilling this interval with mud is becoming more common. The mud is lost to the seafloor, but it does allow pushing the casing point deeper. The following are additional points to consider.

1.1.9.1 Pilot holes

Dynamic kill easier to perform in smaller hole

This is a smaller diameter hole (9-7/8" or 8-1/2") than would be necessary to run the conductor casing. They are recommended for areas of unknown pore pressure because in the smaller hole, it will be easier to a perform dynamic kill and will require smaller kill mud volumes in the event that pore pressure greater than seawater is encountered.

1.1.9.2 Kill mud weight volumes

Kill weight mud volume: 200% open hole plus 100% cased hole

It is necessary to have the appropriate volume of kill weight mud on board when drilling riserless. A volume of 200% of the open hole volume (allows for wash out) and 100% of the cased hole volume is recommended. Some operators who went with less mud volume ended up with the well flowing. The smaller hole allows maximizing the flow while spotting kill mud. The greater flow will minimize cut in weight if the hole is flowing and will also get as much dynamic assistance as possible.

Kill mud weight: Combination of seawater and kill mud typically must exceed 9.5 ppg to achieve control

1.1.9.3 Kill mud weight

It is recommended that a potential flowing sand be assumed to have a pore pressure of 9.3 ppg equivalent and that 9.5 ppg equivalent on bottom is desired. It is unlikely that a sand could exceed the 9.3 ppg due to the limited overburden. Thus, if the combination of seawater and kill mud weight can exceed 9.5 ppg it is likely the hole can be controlled. Kill mud example calculations

Example 1:

5,000' water depth, 1,500' of 20" to set.

9.5 ppg * 0.052 * 6,500 = KMW * 0.052 * 1500' + 8.6 * 0.52 * 5000'

$$KMW = \frac{9.5 * 0.052 * 6{,}500 - 8.6 * 0.052 * 5{,}000}{1{,}500' * 0.052}$$

KMW = 12.5 ppg

Example 2:

7,000' water depth 1,200' of 20" to set.

$$KMW = \frac{9.5 * 0.052 * 8{,}200 - 8.6 * 0.052 * 7{,}000}{1{,}200' * 0.052}$$

KMW = 14.75 ppg

Example 3:

2,000' water depth 1,500' of 20" to set:

$$KMW = \frac{9.5 * 0.052 * 3{,}500 - 8.6 * 0.052 * 2{,}000}{1{,}500' * 0.052}$$

KMW = 10.7 ppg

Drilling Fluid - Seawater

Seawater is the most common fluid used to drill this interval. High viscosity gel sweeps are pumped regularly to assist cleaning the hole.

Drilling Fluid - Mud

The practice of using mud to get 20" to a greater depth below the mud line is increasing. The resulting increase in leak off contributes to setting each additional casing string deeper than otherwise possible. This requires that a large volume of mud be available, greater than most rigs can hold. Barges are available to store mud.

Connectors

Flush ID, external upsets

Connectors for 20" conductor are the same as those for 30" or 36" with the exception of being flush ID and having an external upset. Having the flush ID does not restrict future casing strings. The external upset eases running with side door elevators.

1.2 Shallow Water Flow Control Guidelines

See also *Well Control Procedures, 2.8, Well Control Prior to BOP Installation/SWF*

The shallow water flow (SWF) guidelines include the following areas:

- Geophysical prediction
- Pore pressure and fracture gradient prediction
- Drilling techniques
- Cementing techniques
- Mechanical shut off devices
- Remedial operations and P & A concerns

1.2.1 Summary

In the Gulf of Mexico deepwater area, shallow water flows exist and have resulted in costly well control problems. Shallow water flows are uncontrolled water flows with returns to the seafloor resulting from natural or induced overpressures in the shallow (tophole) section.

Narrow margin between pore pressures and fracture pressures

They exist in water depths greater than 500 ft in the interval from 200 feet to 2,000 ft below the mudline. Overpressures are marginally greater than hydrostatic (usually in the 9.3 - 9.4 ppg range) but can be higher. Shallow flows are difficult or impossible to stop because of the narrow margin between the pore pressures and fracture pressures.

Rapid sedimentation is most likely cause of SWF

Types of SWF include induced fractures, induced storage, geopressured sands, and the transmission of geopressured sands through cement channels. The geopressured sands can originate from several different mechanisms including the following:

- loading by rapid sedimentation
- sand collapse
- gas charging
- salt tectonics

The most likely cause is rapid sedimentation.

The flows appear widely scattered in the Gulf of Mexico deepwater areas and seem possible in virtually any deepwater region in the GOM. However not all sites will have overpressured sands and SWF potential. The Deepstar Consortium has compiled detailed information on SWF along with maps of occurrences. These are available for purchase on compact disk.

In attempts to extend casing points in order to reach well total depth, the casing setting depths have been pushed to approximately 2,000 ft below the mudline. This hole section is normally drilled riserless. While drilling this section, the problem can occur after sweeps to clean cuttings reduce hydrostatic forces and allow the zone to flow.

In these cases, placement of kill mud in the open hole is required to shut off the flow and drilling is normally ceased.

Cementing transition phase reduces hydrostatic forces

Problems with SWF can also occur after running the conductor string and cementing. When the cement is in the transition phase, hydrostatic forces are reduced and the zone flows disturbing the cement before it can set up. This results in an uncontrolled flow to the seafloor. Remediation at this point is usually not successful as the operation usually disturbs the area and makes the problem worse.

Consequences of uncontrolled shallow water include:

- seafloor mound, crater, or subsidence compromising seafloor location
- loss of well support and buckling of structural casing
- compromised wellbore integrity resulting in loss of well control
- abandonment of well
- drilling and project delays of days to months
- millions of dollars of incremental expense

Guidelines to help contend with this problem include discussions of the following:

- geophysical prediction

- drilling techniques
- pore pressure and fracture gradient prediction
- cementing techniques
- mechanical shut off devices

These issues are addressed below, as well as remedial operations and plug and abandonment concerns. For more detailed information, references on this topic are included in the complete list of references at the end of the Well Planning Section.

Further information sources identified in References at the end of the Well Planning Section

A CD-ROM is available through Deepstar which includes data from over seventy wells. Shallow water flow incidents can be captured on the web at:

www.gomr.mms.gov/homepg/offshore/safety/wtrflow.html

Shallow water flow area maps are available from the MMS at 504-736-2947. A SWF Forum was held in June 1998 and proceedings are available on CD-ROM by contacting:

Energy Research Clearing House (ERCH)
4800 Research Forest Dr.
The Woodlands, TX 77381

Or e-mailing sparkman@erch.org

1.2.2 Geophysical Prediction

Predicting whether SWFs will exist at a given location has proven to be very difficult. Several techniques exist to predict the presence of sands but predicting whether the sands are sufficiently geopressured is difficult.

When applied to the interpretation of high resolution geophysical survey records, sequence stratigraphy permits identification and mapping of potential shallow flow sands and seals

Sand formations are regularly deposited during sea level lowstands and can be identified by the seismic stratigraphic method. When applied to the interpretation of high resolution geophysical survey records, sequence stratigraphy permits identification and mapping of potential shallow flow sands and seals. This interpretation should involve all seismic data available including 2D shallow hazard and 3D seismic data. Special processing of this data is required.

One method suggested for SWF potential is as follows:

> Calculate the shallowest sedimentation rate by seismic correlation to the shallowest available offset paleo data. If the shallow sedimentation rate is less than 500 ft per million years at the planned drilling site, the sands should have no significant pressure. If the rate is higher than 500 ft per million years treat the sands below the seal as pressured. (Alberty 1997)

Seismic data should be tied to any well control in the area

Seismic data should be tied to any well control in the area. In general the focus should be on channel and slump features which usually have the highest probability of sand. One method uses RMS amplitude maps between key sequence boundaries, time, and horizon slices, and various edge detection maps. Another method would be to obtain high resolution 3D shallow hazard surveys, but this is very costly.

Once the sand prone facies have been mapped, well locations can possibly be adjusted to avoid the features or casing programs can be modified. When drilling to the

casing point, real time logging which drilling (LWD) correlations should be made to ensure the flow zone is not penetrated prior to reaching the casing point. These LWD correlations include gamma ray, resistivity and pressure while drilling (PWD) data. Pressure while drilling devices prove helpful as they indicate increases in bottomhole pressure as the zones start to flow. Onsite interpretation by the drilling engineer and geoscience personnel is highly recommended.

PWD devices indicate increases in bottomhole pressure as SWF zones start to flow

1.2.3 Pore Pressure/Fracture Gradient Prediction

Proper mud weight minimizes induced fractures and wellbore storage effects while maintaining hydrostatic to control the flow

The key to successfully drilling through SWF sections is proper determination of fracture gradients and pore pressures. Proper mud weight will minimize induced fractures and wellbore storage effects while maintaining hydrostatic to control the flow. It is common to drill with at least a 0.3 ppg margin between mud weight and fracture gradient.

Precise pressure prediction is difficult due to the unconsolidated nature of these shallow sediments. Large variances exist between wells due to the depositional environment and offset well information is limited due to the exploratory nature of the wells drilled. Review of seismic data on thin intervals has been suggested as a way of determining pressures. This may require special processing or different data sampling equipment. Detailed geological interpretation of seismic data is required to determine whether the depositional environment exists which leads to SWF potential. This interpretation should be tied to offset well data where available. Outsourcing interpretive expertise may be necessary.

Pressure measurements provided by open hole formation pressure testers may be beneficial for future offset and development drilling

Some operators have run open hole formation pressure testers to obtain accurate pressure measurements. Assuming this data collection process is successful, this data can be very beneficial for future offset well and future development drilling. Pressure while drilling (PWD) tools in conjunction with LWD tools may be helpful in pore pressure estimation.

The collection of fracture gradients at casing points is beneficial, but not without risk of irreparable damage.

1.2.4 Drilling Techniques for SWF Intervals

The drilling techniques discussed in this section are designed to accomplish the following:

- provide formation evaluation logging over shallow flow zone
- select casing point above shallow flow zone
- eliminate or minimize shallow flow zone charging
- check for shallow flow
- provide proper mud properties for cementing

Minimize effects of SWF

Increase probability of controlling SWF

Applying these techniques will minimize the effects of shallow flow and maximize probability of successfully controlling the zone.

1. Avoid drilling in locations that have shallow flow potential. This will require a coordinated effort with the geoscientist in techniques presented in the predictions section.

Jet string and controlled jetting

2. Install jet string using controlled jetting techniques. Use of drill-in motor assemblies usually minimizes soil disturbance as it reduces the amount of seawater pumped. (Some evaluation into driving the initial string to extended depths).

Minimize hole diameter

3. Minimize the diameter of the hole drilled. This will help for cuttings removal. The drilling of the hole in a single pass (i.e. no pilot hole) will also minimize washout. Using larger drill pipe will also help in cuttings removal slightly. Minimize circulations to reduce hole enlargement.

Gel or foam slurry sweeps to ensure cuttings removal

4. Pump sweeps to clean the hole every stand. This will prevent charging of sands caused by cuttings load. Use low fluid loss mud where economically viable. The sweeps can consist of gel or foam slurries for better carrying capacity. The gel sweeps along with dye tracers, or other tracers such as mica, can be used to quantify annular flow rate by timing returns at constant circulation rates.

5. Keep low fluid loss (less than 10 cc/30min.), low, flat gel strength (10 sec., 10 min., 30 min.), YP- 10, PV-15 mud ready in the pits to spot in the event of a flow. The mud weight should be sufficient to offset the hydrostatic pressure of the zone with a slight margin, but not too high to cause fracturing of weak formations or ballooning. One suggested method of calculation is to assume the formation pressure is 80-90 per cent of the overburden. Repeat formation testers have been used to determine pore pressure of the zone. The mud should have low fluid loss and provide a thin filtercake. The low gel strengths will allow for efficient cement displacement at the low annular velocities. Pump twice the open hole volume. Do not use standard kill mud as the mud is not consistent with good cement placement practices. Also, this mud could cause wellbore hydration problems. It may be necessary to include loss circulation material to maintain hydrostatic by preventing losses in upper sections of the hole. Dynamically kill the flow at maximum rate. It is nearly impossible to pump too fast, as annular pressure drop is very low. If the well is not dead after pumping two hole volumes, then further pumping is rarely effective. A change in density or pump rate is warranted. U-tubing will occur after shutting down pumps. This will help maintain hydrostatic but could give indications of continued flow. Qualitative interpretations of prior videos can be used to judge whether the well is dead. Ultimately, if the drill pipe is filled with seawater behind a successful kill, all annular flow should cease.

6. Use LWD near the bit. This helps in correlation to seismic for casing point selection. It will also minimize the amount of a sand which is penetrated. Precise formation temperature is desired for cement formulation. This will rule out use of drill ahead tools unless vendors can supply measurement below motors in the larger drill string sizes. Typically distances from LWD to bit are in the 8' to 15' range. Correlation from data obtained in large holes (24") has proved successful. Verify that the LWD equipment has maximum circulation rate capability compatible with dynamic kills in pilot holes.

7. If a sand is penetrated, the hole should be circulated clean and pumping stopped to check for flow. If flow is encountered, observation should determine whether the flow is persistent or dissipates over time. Charging of sands due to cuttings load can give a false indication of a flow zone. An ROV should be monitoring the wellhead

continuously while drilling throughout the potential interval. Also if broaching is a concern the area up to a radius of 300 feet should be checked by the ROV. In some cases if may be prudent to monitor until after surface casing is set.

Casing point

8. The casing point should be as close as possible to the shallow flow zone to maximize the shoe integrity. However, consideration to lithology should prevail as a competent shoe is critical.

9. If flow is encountered and the casing is set above the flow zone, then spot heavy mud below casing point to act as base for cement. A casing packer can help in potential cement segregation as well as keep the flow from disturbing the cement during transition.

Drilling through flow zone

10. If drilling proceeds through the flow zone, flow from the zone should be minimized to reduce formation accumulations at the mudline and hole enlargement. Some operators have elected to drill with kill mud with returns lost at the mudline to prevent water flow and limit hole erosion. The large volume of weighted mud that is required can be a logistical challenge.

Cementing practices

11. Use production cementing practices when cementing the strings above and across the shallow flow interval. Spot mud as stated in practice No. 5 above. Use centralizers. Preflush density should not allow the zone to flow. (i.e. do not use seawater ahead of the cement, maintain hydrostatic during cement job). The use of inner string cementing can reduce volumes pumped and contamination. The inner string or casing should be filled with kill mud to prevent circulation of seawater. The well must be dead prior to cementing.

12. Reduce surge when running casing. Use convertible float shoes if necessary.

13. Use flow resistant cement slurries as detailed in cement section.

Testing shoe

14. When testing shoe, give some thought as to whether the test is taken to leak-off. Taking the test to leak-off may cause irreparable damage. This practice will be dependent upon the needs of the well and data from offset wells.

Reciprocating casing across flow zone

15. Some operators have reciprocated casing place across the flow zone. This will provide for better cement displacement, but it is imperative that the casing hanger

or wellhead land so that the mechanical seal can be actuated.

Well spacing

16. At development locations well spacing should be maximized to minimize exposure from inadvertent flow from adjacent wells. Also, drilling operations should include alternate sequencing to maximize the time and distance between operations on adjacent wells.

26" drift riser

17. Some operators have used 26" drift riser. Difficulties exist in adjusting the density of the mud column in the riser due to the narrow pressure differences between the pore pressure and the fracture pressure. This adjustment is difficult because of cuttings loading and large mud volumes. It is also possible to produce a shallow water flow by charging up a shallow zone. Breaching can also occur. The time and expense of handling this riser is considerable.

18. New technology is being developed and should be tested soon. These include in-situ polymerization (injection of monomers and activators to inhibit flow), and driving structural casing through the SWF zone with an underwater hammer. These technologies are reported to be attempted soon. One other suggested method with the use of dual activity rigs is to drill an adjacent hole and inject refrigerant to freeze the SWF zone to eliminate flow until cement is placed and set up.

1.2.4.1 Setting and cementing casing in SWF zone

Cementing objectives in SWF zones

The two main objectives of cementing in SWF areas are as follows:

- achieve a competent seal that will prevent fluid movement
- provide structural support for the casing

Successful conductor casing cementing requires good mud management, short slurry transition times, and mud and cement slurry weights which are compatible with formation pore and fracture gradients. Containment of the SWF is complicated by weak formations that can fracture and cause loss of mud and cement returns.

1.2.4.2 Deepwater cementing design parameters

Design parameters for deepwater cementing include pump time, free water, fluid loss, rheology, transition time, density, compressive strength, and compressibility.

Free Water

Excessive free water may lead to channeling

If the cement slurry has excessive free water, channels will form that may result in a loss of zonal isolation. Free water may result in slurry instability and may cause a change in volume due to leak-off into the formation. As water is removed the pressure in the column will drop possibly leading to an influx of reservoir fluids. Settling will cause density differentials that may result in insufficient hydrostatic pressure to maintain zone control.

Rheology

Lead slurry friction pressure (FP) must be greater than FP of spacer and less than FP of tail slurry

The primary concern is efficient annular fluid displacement. The lead slurry must generate a friction pressure greater than the spacer and less than the tail slurry.

Transition Time

Shortest possible slurry transition time

The slurry transition time should be kept as short as possible to reduce exposure to flow. Transition time is defined as the time lapse between onset of hydration until the cement gains sufficient internal gel strength to prevent flow or influx.

Fluid migration possible during transition time

During transition time the shallow flow can migrate up through the setting cement slurry, forming channels that destroy cement integrity. Fluid migration is possible during the transition time because the cement column begins to support itself and stops exerting hydrostatic pressure on the fluid source, but does not have enough compressive strength to prevent fluid migration. A variance of a few degrees can adversely affect transition time.

Density

The cement weight as well as spacer weight must be designed to maintain hydrostatic pressure during the displacement process without exceeding the formation strength. In order to examine the dynamic results of pumping the well fluids, spacers, and cement slurries, computer simulations need to be performed. This ensures that the formation pressure is contained while the fracture pressure of the formation is not exceeded during and after the cementing process.

Compressive Strength

Achieving desired compressive strengths requires special cement blends

The cement must develop adequate mechanical properties to support the casing for the life of the well. Obtaining the compressive strength needed requires special cement blends at the densities and temperatures involved.

Compressive Cements

Compressed gas in cement will maintain pressure in the slurry above the pore pressure as the cement is in the transition phase. The large volume of gas will also help compensate for slurry volume reductions due to fluid loss and volumetric shrinkage.

Two major cement systems have been developed for SWF control as follows:

- Microfine cement in combination with microspheres – provides a lightweight high performance cement slurry
- Nitrogen foamed cement provides a variable density high performance slurry

Microfine Cement

Microfine cement provides the following features:

- Allows control of the density to prevent formation fracture enabling full returns during placement
- Provides for transition times of about 30 minutes
- Has a low fluid loss to maintain hydrostatic

- Provides the compressive strengths needed at low densities in the cool temperature environment.

Densities range from 11.0 ppg to 14.0 ppg for the lead with tail slurry densities ranging from 15.2 - 16.4 ppg.

Nitrogen Foamed Cement

Nitrogen foamed cement provides the following features:

- Allows control of density on the fly
- Provides for transition times of about 45 minutes
- Provides fluid loss control
- Has low free water
- Provides superior compressive strength and improved ductility at low densities in the cool environment

Nitrified foam cement features:
+ **Efficient mud displacement**
+ **On-the-fly density control**
+ **Short transition times**
+ **Best compressibility possible to prevent flow**

Additionally, nitrified foam cement offers the best compressibility possible to prevent flow and provides efficient mud displacement.

Requirements for the use of nitrified foam cement are as follows:

- additional specialize equipment, software, and personnel expertise
- cryogenic fluid on deck
- higher friction pressure losses
- usually specialty blends
- refrigerated test equipment, which is limited

Densities range from 11.0 - 12.5 ppg for the lead with base slurry for tail at 15.2 ppg. The density is easily changed as the amount of gas injected and the density can be varied throughout the column. Nitrogen cement has higher friction pressure losses.

Slag cement can convert drilling mud to cement

Slag cement has been used by one operator. The slag cementing process uses blast furnace slag to convert drilling mud into cement in conjunction with cheap accelerators and thinners. Compatibility of fluids reduces the impact of drilling fluid contamination of cement, and can lower cost and reduce waste.

It is not in widespread use due to failure of technology to combine simplicity, broad applicability to a variety of drilling fluids, and significant cost savings. Often mud contaminants from the formation require a new build of the mud system and displacement in the hole, thereby significantly reducing cost savings. Also slag cement is not suited for shallow flow as the low seafloor temperatures greatly reduce the hydration of the blends.

In general all techniques used in production casing cementing should be considered. Other issues which should be evaluated include the following:

- Centralization of the casing
- Rotation and/or reciprocation of the casing strings (may not be feasible due to the mechanical features of the casing's hanger mechanisms)
- Lead cement should set after the tail cement thereby maintaining hydrostatic pressure until a seal is formed
- High performance cement should be placed across the flow interval
- Cement should be pumped in place as quickly as possible
- Seawater circulation prior to cement job should be minimized as outlined in drilling techniques section
- Dyes in spacers and cement can be useful as an informational aid
- The ROV should be used to capture cement samples at the mudline to determine if cement returns reached mudline and for future cement volume adjustments
- Sodium silicate flushes are recommended by some vendors to improve filter cakes

1.2.4.3 Mechanical shut off devices

Mechanical shut off devices are designed to provide a second sealing mechanism along with the cement. During cement transition, hydrostatic pressure is reduced and the mechanical devices provide a pressure seal which prevents the SWF zone from disturbing the cement.

Mechanical shut-off devices provide pressure seal during slurry transition time

This mechanical control is usually accomplished in two ways. First, the shoe of the jet string is effectively deepened by installing an intermediate string between the jet string and the casing which is run across the shallow flow zone. This intermediate string provides the shoe integrity needed to seal the zone as the jet string shoe integrity is not sufficient to hold the SWF zone. Secondly, a mechanical device is used to seal the annulus between the intermediate string and the casing string which is run across the SWF zone.

There are some exceptions but the majority of the systems use these principles. An alternate approach is to drive the initial jet string to depths sufficient to provide a fracture gradient which will hold the shallow flow zone. Driving to 800 feet below the mudline has been stated to be feasible. According to Deepstar, a field test will be performed in the near future.

Provided below are diagrams of the mechanical systems that have been designed to control shallow flow. Each drawing is followed by a summary of the concept, features of the system, and advantages and disadvantages.

Most of the systems described below have been used while a few are conceptual. Any of these mechanism types can be combined to create additional methods of mechanical shut-off.

Mechanical shut-off systems can be modified for large jet strings (38", 42")

These systems could be modified to include larger jet strings such as 38" and 42" depending on the deepwater structural requirement.

Use with guideline and guidelineless drilling systems

Most of these systems can accommodate guideline and guidelineless drilling systems. Guideline and guidelineless systems which use a guide base on the wellhead housing may require additional non standard equipment. Guidelineless systems which use a funnel down approach are easily accommodated. These mechanical shut-off devices are evolving and at least one new slim hole system design has been proposed. Reliance on the wellhead vendors is highly recommended in order to review the latest techniques available.

Drilling with pin connector and 26" riser

Most systems can provide for drilling with a pin connector and 26" riser to provide hydrostatic control of the flow zone. However, use of a riser can cause broaching of the casing shoe and/or charging of sands due to cuttings load. Also, the cost of running and retrieving the riser and procurement have to be considered.

Guide and assist (G&A) refers to guideline systems which use posts on a frame attached to the wellhead housing. Guidelineless re-entry assembly (GRA) refers to guidelineless systems which incorporate a funnel attached to the wellhead housing.

The system used for a particular exploratory or development well will depend upon the individual well or development location requirements and the operator's philosophy, and will require risk management.

Diagrams of several systems are included on the following pages.

SHALLOW WATER FLOW CONTROL

30" w/ ROV valves, 20" w/ 18 3/4" HP hsg.

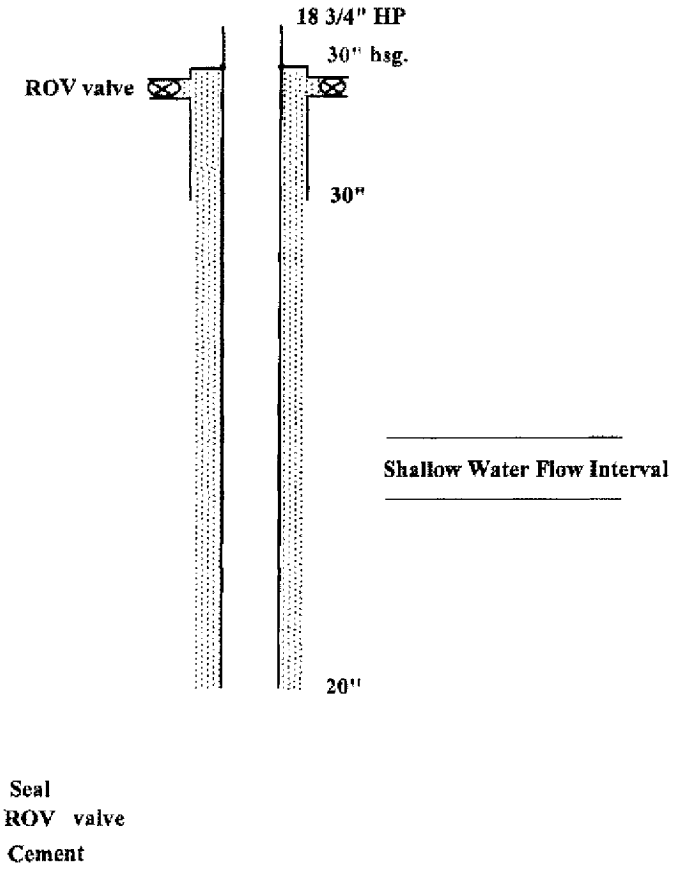


Figure 1-3 SWF Concept 1: 30" w/ ROV valves, 20" w/ 18-3/4" HP housing.

599938583

Concept

1. Jet 30" with ROV valves on 30" housing.
2. Drill through zone riserless.
3. Run and cement 20" across zone with standard 18-3/4" HP housing.
4. Allows shut off of zone via cement in 30" x 20 " annulus and ROV valves.

Features

- 30" x 20".
- Guideline or guidelineless.
- If G&A is run, valves incorporated in G&A with seal between G&A and 30" housing.

Advantages

Standard equipment.

Disadvantages

30" shoe integrity is usually not sufficient to shut-off flow. Broaching of 30" results.

SHALLOW WATER FLOW CONTROL

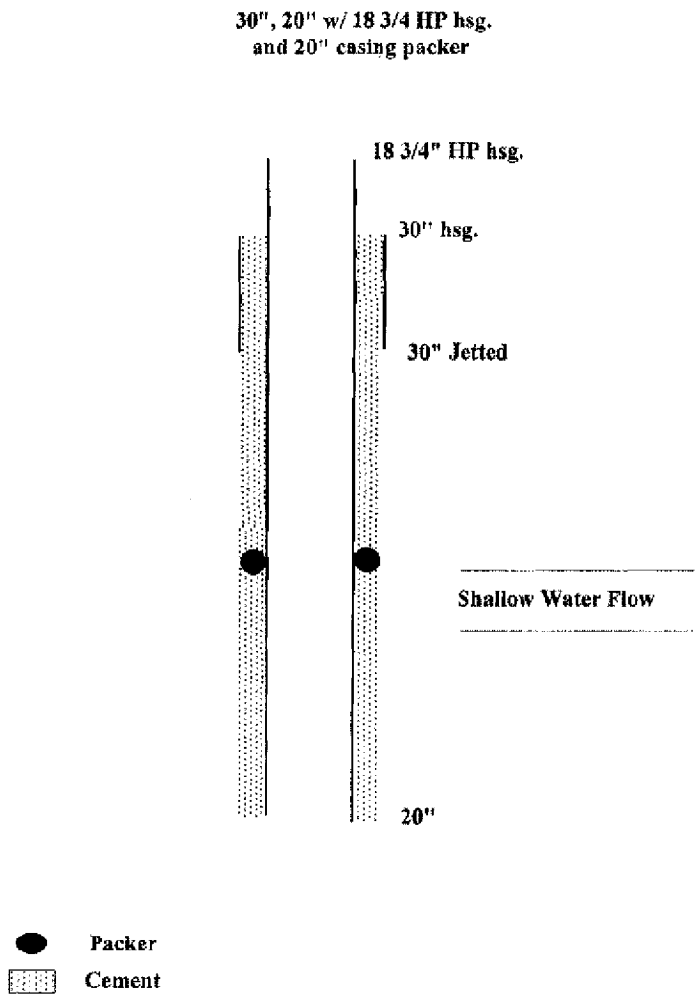


Figure 1-4 SWF Concept 2: 30", 20" w/ 18 3/4 HP and 20" casing packer.

599938585

Concept

1. Jet 30".
2. Drill conductor hole.
3. Run and cement 20" across zone with standard 18-3/4" HP housing with 20" casing packer above zone.
4. Allows control of flow zone with packer and cement.

Features

- 30" x 20".
- Can use 36" with bushing on 18-3/4" housing.
- Can use guideline or guidelineless equipment.

Advantages

- Standard equipment except for 20" packer.
- Packer provides mechanical seal in addition to cement.

Disadvantages

- Packer inflation dependent on wiper plug landing and holding pressure.
- If packer is inflated with excess volume, elements will rupture.
- If packer checks don't activate, a leak point will exist in the middle of the string if not inflated with cement.
- Packer can be inflated with cement but requires complicated interstring assembly.
- Packer must hold minimal pressure until cement sets up.
- If packer does not design or hold, rely on cement only to control flow.

SHALLOW WATER FLOW CONTROL

30", 20" w/ 18 3/4 HP hsg. & 16" and 20" casing packer

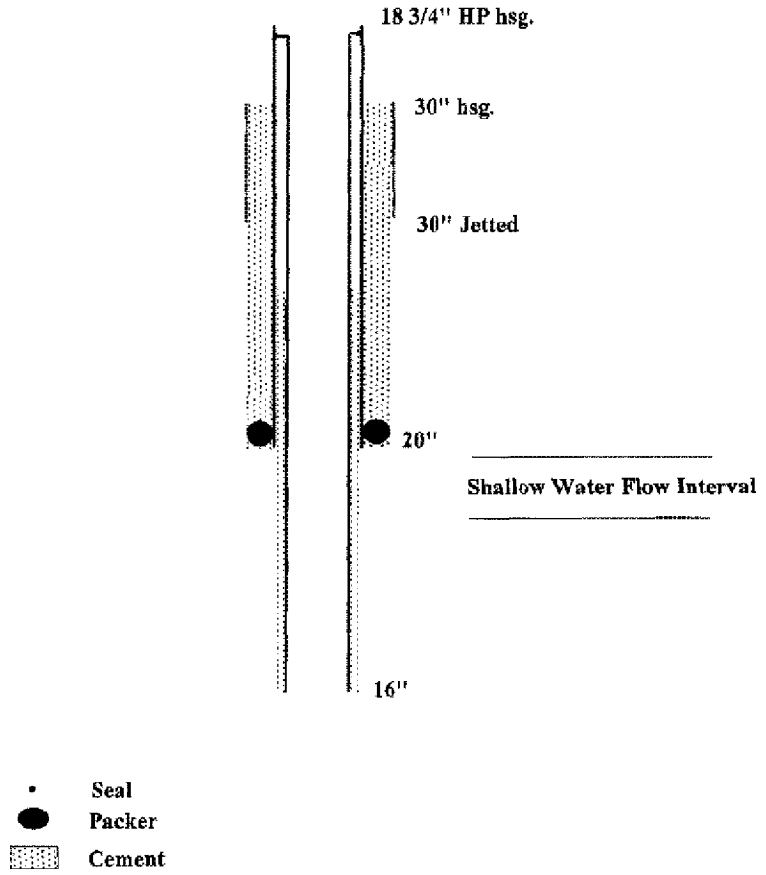


Figure 1-5 SWF Concept 3: 30", 20" w/ 18 3/4 HP hsg. & 16" and 20" casing packer.

599938587

Concept

1. Jet 30".
2. Drill conductor hole.
3. Run and cement 20" above zone with standard 18-3/4" HP housing and 20" casing packer above zone.
4. Allows control of flow zone with packer and cement.

Features

- 30" x 20".
- Can use 36" with bushing on 18-3/4" housing.
- 16" can be set below mudline or in 18-3/4" wellhead.
- Can use guideline or guidelineless equipment.

Advantages

- Standard equipment except for 20" packer.
- Packer provides mechanical seal in addition to cement (packer must hold minimal pressure until cement sets up).
- Can inflate packer with cement behind wiper plug.

Disadvantages

- Packer inflation dependent on wiper plug landing and holding pressure.
- Limits number of casing strings to reach total depth.
- If packer does not hold, rely on cement only for control.
- Possible difficulty setting 16" packoff with flowing sands.

SHALLOW WATER FLOW CONTROL

30", 24", 20" w/ 18 3/4" HP hsg.

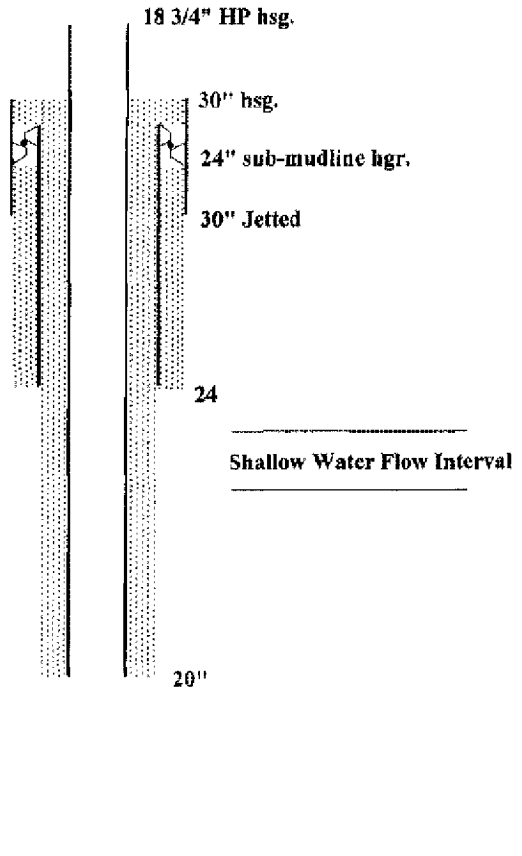


Figure 1-6 SWF Concept 4: 30", 24", 20" w/ 18-3/4" HP hsg.

599938589

Concept

1. Jet 30" with landing shoulder.
2. Run 24" casing with sub-mudline hanger to just above shallow flow zone.
3. Pick up hanger off landing shoulder and cement.
4. Set down hanger.
5. If annulus test required, run 20" riser on pin connector.
6. Can drill through with or without pin connector and 20" riser.
7. Retrieve riser if run.
8. Run and cement 20" across zone with standard 18-3/4" HP housing.
9. Allows shut off of zone via cement in 24" x 20" annulus and mudline hanger seal and the 24" shoe provides integrity to prevent broaching.

Features

- 30" x 24" x 20".
- 24" sub-mudline hanger which lands in shoulder in 30".
- Can use 36" x 26" with bushing on 18-3/4" housing.
- Can use guideline or guidelineless equipment.
- Has elastomeric seal on 24" hanger.
- Possible 24" seal design - high reliability (metal to metal) with testing without riser.

Advantages

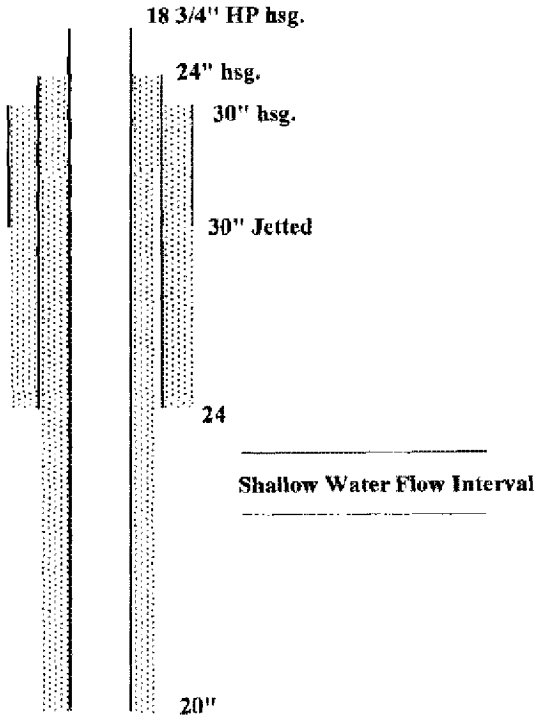
- Standard equipment except for 24" sub-mudline equipment.
- Option to eliminate 24" does not require any special equipment.

Disadvantages

- Relies only on cement to seal off flow in 20" x 24" annulus (cannot maintain control of flow during cement transition).
- Required to lift 24" hanger off ring during cementing.
- Poor cementation of 30" x 24" annulus and seal leak requires riser and bit trips for remedial cementation and clean out for test.
- Limited through bore on 30" mudline ring requires hole opening.
- Requires hole opening for 20".

SHALLOW WATER FLOW CONTROL

30", 24", 20" w/ 18 3/4" HP hsg.



Cement

Figure 1-7 SWF Concept 5: 30", 24", 20" w/ 18-3/4" HP hsg.

Concept

1. Jet 30".
2. Drill conductor hole.
3. Run 24" casing with modified 30" housing to just above shallow flow zone and cement.
4. Drill through with or without pin connector and 20" riser.
5. Retrieve riser if run.
6. Run and cement 20" across zone with standard 18-3/4" HP housing.
7. Allows shut off of zone via cement in 24" x 20" annulus only and 24" shoe provides integrity to prevent broaching.

Features

- 30" x 24" x 20".
- 24" intermediate wellhead housing which is modified 30" housing which locks into 30".
- G & A run on lower standard 30" housing.
- Can use 36" with bushing on 18-3/4" housing.
- Can use guideline or guidelineless equipment.

Advantages

- Standard equipment except for 24" housing.
- Option to not run 24" does not require any special equipment.
- Does not require sub-mudline, hanger seal arrangement.

Disadvantages

- Wellhead sits higher than standard 30"/20".
- Bending capacity (fatigue) limitations as only 20" x 24" can be preloaded.
- Relies only on cement to seal off flow in 20" x 24" annulus (cannot maintain control of flow during cement transition).
- Requires hole opening for 20".

SHALLOW WATER FLOW CONTROL

30", 24", 20" w/ 18 3/4" HP hsg.

w/ ROV Valve on 24" hsg.

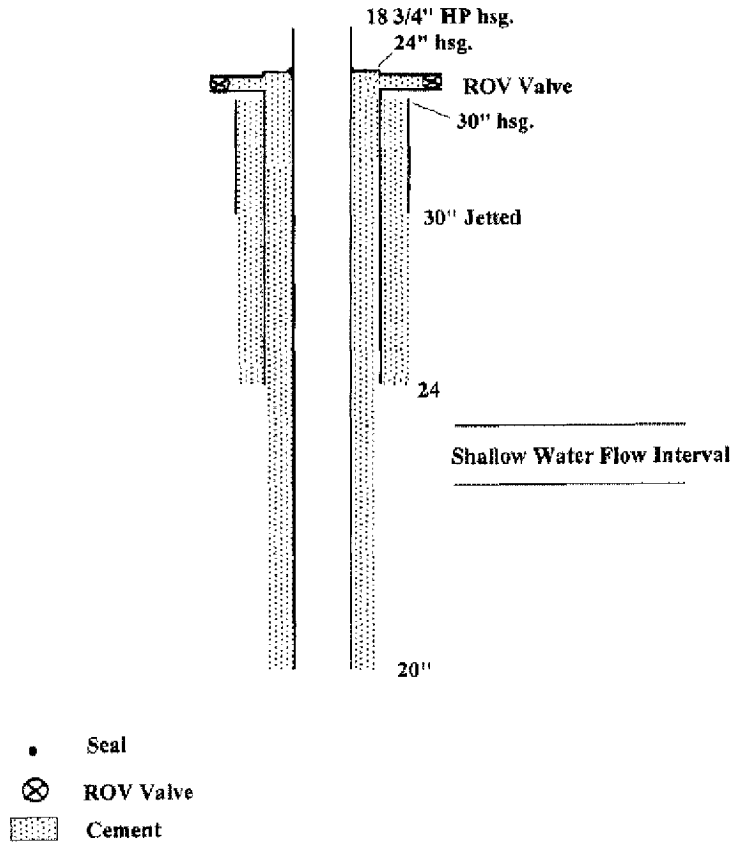


Figure 1-8 SWF Concept 6: 30", 24", 20" w/ 18-3/4" HP hsg w/ ROV valve on 24" hsg.

Concept

1. Jet 30".
2. Drill conductor hole.
3. Run 24" casing with modified 30" housing to just above SWF zone and cement (outlets with ROV valves connected to 24" housing ports).
4. Drill through with or without pin connector and 20" riser.
5. Retrieve riser if run.
6. Run and cement 20" across zone with standard 18-3/4" HP housing.
7. Allows shut off of zone via ROV valve in flow event after cementing and 28" shoe provides integrity to prevent broaching.

Features

- 30" x 24" x 20".
- 24" intermediate wellhead housing which is modified 30" housing and locks into 30" housing.
- Has outlets with ROV valves.
- Uses standard 30" and 18-3/4" housings.
- Can use 36" with modified 36" for 24"/26" housing, with bushing for 18-3/4" housing.
- G & A run on lower standard 30" housing.
- Can use guideline equipment.

Advantages

- Standard equipment except for 24" housing.
- Option to not run 24" does not require any special equipment.
- Does not require sub-mudline hanger seal arrangement.
- Allows mechanical control of flow during cement transition.

Disadvantages

- Wellhead sits higher than standard 30"/20".
- Bending capacity limitations (fatigue) as only 20" x 24" can be preloaded.
- G & A run on 30" housing (stripping over valves during abandonment required).
- Compatibility with GRA needs evaluation.

SHALLOW WATER FLOW CONTROL

36"/30", 26"/24", 20" w/ 18 3/4" HP hsg.

w/ 18 3/4" x 30" Housing Seal

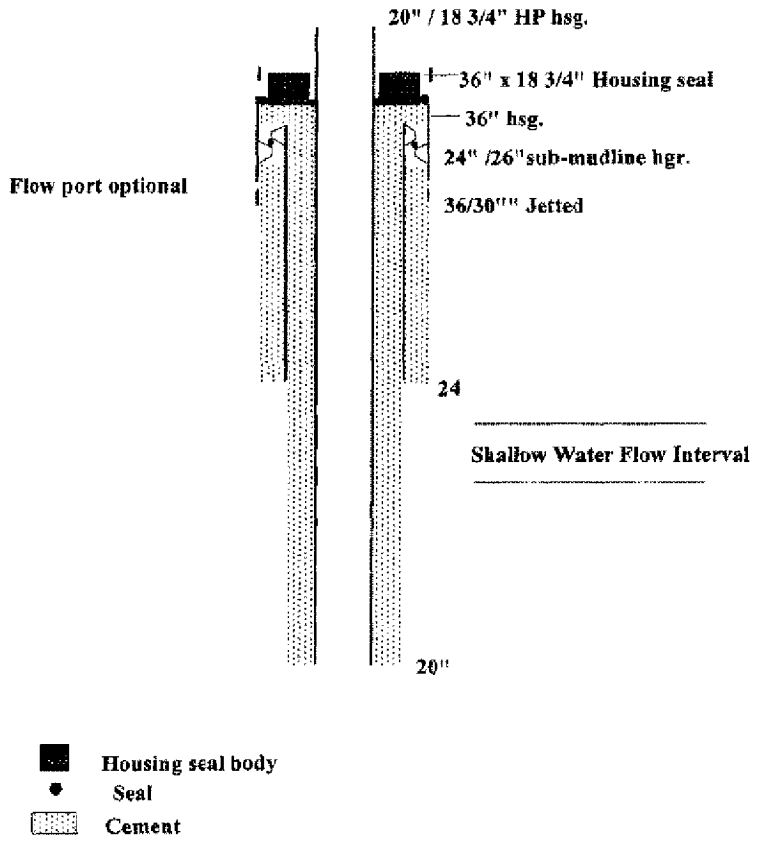


Figure 1-9 SWF Concept 7: 36"/30", 26"/24", 20" w/ 18-3/4" HP hsg. w/ 18-3/4" x 30" Housing Seal.

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Concept

1. Jet 30" or 36" with landing ring.
2. Drill conductor hole.
3. Run 24" or 26" casing with sub-mudline hanger to just above shallow flow zone.
4. Pick up hanger off landing ring and cement.
5. Set down hanger.
6. If annulus test required run 20" riser on pin connector.
7. Can drill through with or without pin connector and 20" riser.
8. Retrieve riser if run.
9. Run and cement 20" across zone with 18-3/4" HP housing with housing annulus seal
10. Allows shut off of zone via housing seal which is activated with housing running tool and 24" shoe provides integrity to prevent broaching.

Features

- 36"/30" x 26"/24" x 20".
- 24"/26" Sub-mudline hanger which lands in ring in 36"/30". Could provide metal to metal seal which could be replaceable and testable without riser.
- Can use guideline or guidelineless equipment.
- Can provide return port below mudline hanger to monitor for potential flow.

Advantages

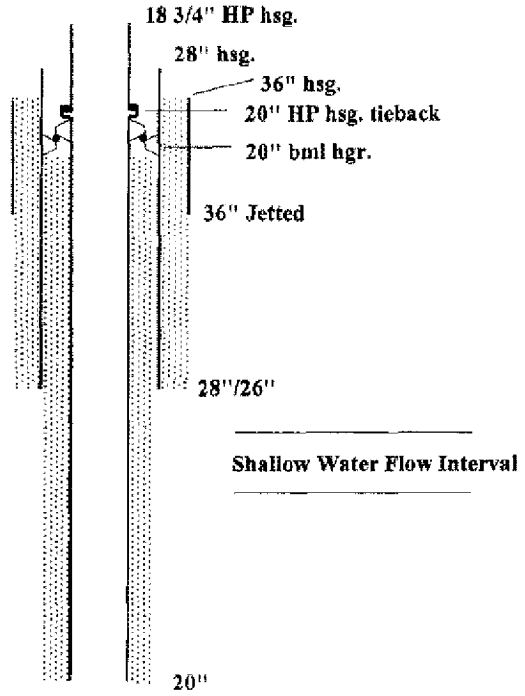
- Provides mechanical control of flow.
- Standard equipment except for 24"/26" sub-mudline equipment.
- Option to eliminate 24"/26" does not require any special equipment.

Disadvantages

- Required to lift 24" hanger off ring during cementing.
- Poor cementation of 30" x 24" annulus and seal leak requires riser and bit trips for remedial cementation and clean out for test.
- Limited throughbore on 30" mudline ring requires hole opening if 30" casing used.
- Requires hole opening for 20" if 24" is used.
- Housing seal in not replaceable.

SHALLOW WATER FLOW CONTROL

36", 28", 20" w/ 20" bml csg. hgr. and packoff
18 3/4" HP hsg. ran and stab into 20" hgr.



Seal
Cement

Figure 1-10 SWF Concept 8: 36", 28", 20" w/ 20" bml csg. hgr. and packoff 18-3/4" HP hsg. run and stab into 20" hgr.

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Concept

1. Jet 36".
2. Drill conductor hole with or without riser.
3. Run 28" to just above SWF zone and cement on 28" housing.
4. Drill through with or without pin connector and 26" riser.
5. Run and cement 20" across zone on mudline hanger with seal (with or without control).
6. Retrieve riser if used.
7. Land 18-3/4" housing into 20" mudline hanger with elastomeric seal.
8. Allows shut off of zone via sub-mudline seal and 28" shoe provides integrity to prevent broaching.

Features

- 36" x 28" x 20".
- 28" Intermediate wellhead housing with sub-wellhead landing shoulder in 28" string.
- Sub-mudline 20" hanger lands and seals in 28" landing shoulder with elastomeric or metal to metal seals which are replaceable and testable with or without riser.
- Uses split 20" string with 20" primary string run through 26" riser latched to 28" intermediate housing.
- Can run and test without riser.
- 18-3/4" housing lands into primary string and seals with elastomeric seals and is retrievable and re-installable in seal leak event.
- Can skip 28" with bushing on 18-3/4" housing.
- Can use guideline or guidelineless equipment.

Advantages

- Allows 20" to be run through flow zone with or without riser control.
- High reliability on 20' x 28" annulus.
- Allows mechanical control of flow.

Disadvantages

- Complicated additional seals.
- Increased inventory.
- 26" riser expense if used.
- If 26" riser is used, broaching of 28" can occur.
- Has an additional intermediary seal in 20" string below 18-3/4" housing which requires additional trip to set 18-3/4" housing.
- Pre-loading of 18-3/4" x 28" requires boot strap tool run.

SHALLOW WATER FLOW CONTROL

36", 26" w/ 26" bml csg. hgr. and packoff, 20" w/ 20" bml csg. hgr. and packoff 18 3/4" HP hsg. ran and stab into 20" hgr.

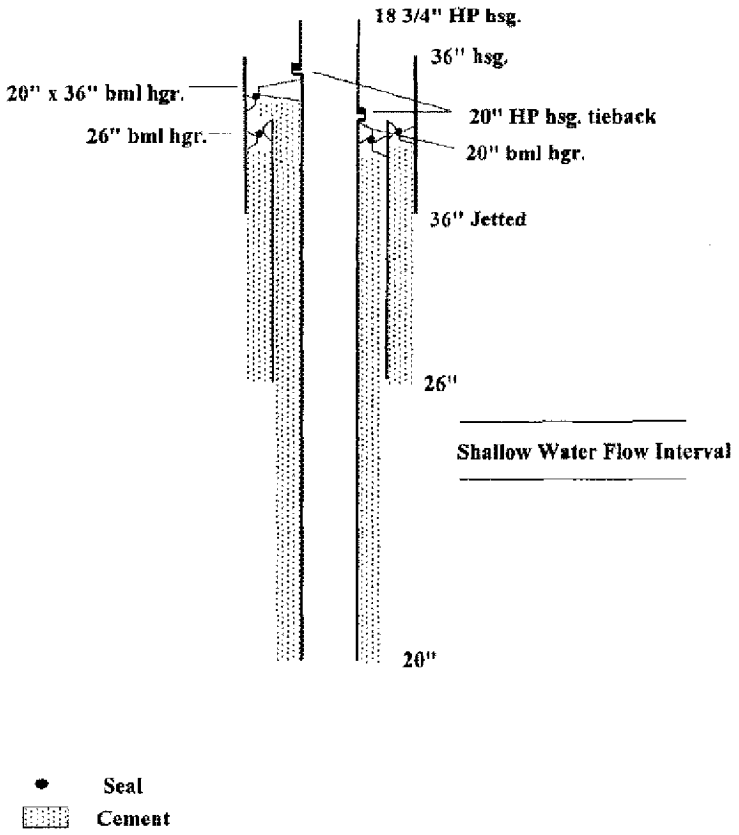

Figure 1-11 SWF Concept 9: 36", 26" w/ 26" bml csg. hgr. and packoff, 20" w/ 20" bml csg. hgr. and packoff 18-3/4" HP hsg. run and stab into 20" hgr.

Concept

1. Jet 36".
2. Drill conductor hole.
3. Run 26" to just above shallow flow zone and cement on sub-mudline hanger with seal.
4. Test seal.
5. Drill through with or without pin connector and 26" riser.
6. Run and cement 20" across zone on mudline hanger with seal (with or without riser control).
7. Retrieve riser if used.
8. Land 18-3/4" housing into 20" mudline hanger with elastomeric seal.
9. Allows shut off of zone via sub-mudline seal and 26" shoe provides integrity to prevent broaching.
10. Option to land 20" on mudline hanger in 26" or 36".

Features

- 36" x 26" x 20".
- Sub-mudline 20" hanger land and seals in 26" hanger with elastomeric or metal to metal seals which are testable with or without riser.
- 26" sub-mudline hanger has seal, which is testable and could be replaceable.
- Uses split 20" string with 20" primary string run through 26" riser latched to 36" housing.
- 18-3/4" housing lands into primary string and seals with elastomeric seals and is retrievable and re-installable in seal leak event.
- Uses bushing attached to standard 18-3/4" HP housing to land into 36" housing.
- Can use guideline or guidelineless equipment.

Advantages

- Allows 20" to be run through flow zone with or without riser control.
- Allows mechanical control of flow.
- Wellhead stack up minimized by elimination of 28" housing.
- Landing 20" into 36" housing reduces running tools and allow setting 26" deeper.

Disadvantages

- 26" riser expense if used.
- If 26" riser is used, broaching of 26" can occur.
- Has an additional intermediate seal in 20" string below 18-3/4" housing which requires additional trip to set 18-3/4" housing.
- Pick up above landing shoulder on 26" required for cementing. If a packoff design is used, pick up is not necessary and the packoff is replaceable and testable without riser.

SHALLOW WATER FLOW CONTROL

36", 26", 20" w/ 18 3/4" HP hsg.

w/ shut off sleeve on 36" hsg.

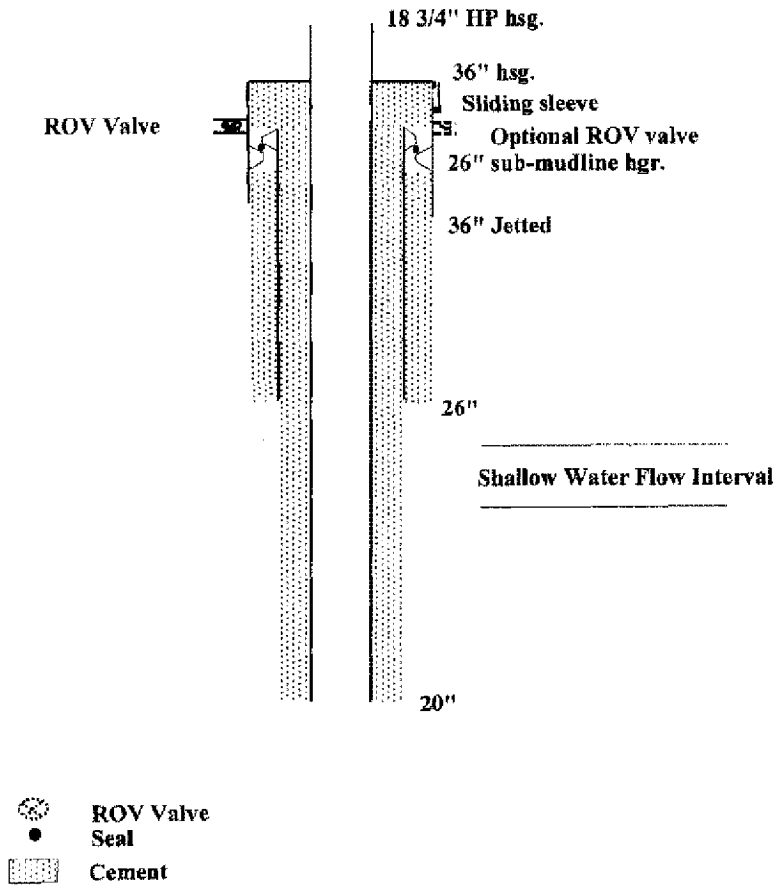

Figure 1-12 SWF Concept 10: 36", 26", 20" w/ 18-3/4" HP hsg. w/ shut off sleeve on 36" hsg.

Concept

1. Jet 36" with 26" sub-mudline landing shoulder and sliding sleeve on 36" housing.
2. Drill conductor hole.
3. Run 26" above flow zone with sub-mudline hanger and seal.
4. Run 20" across zone on 18-3/4" housing with bushing in 36".
5. 18-3/4" housing seals in 36" housing.
6. Sliding sleeve on 36" housing activated with 18-3/4" housing running tool after cementing.
7. Allows shut off of zone via sleeve which shuts off 26" x 20" annulus and 26" shoe provides integrity to prevent broaching.
8. Option to replace sleeve with ROV.

Features

- 36" x 26" x 20".
- 26" sub-mudline hanger with testable seal (metal to metal can be provided).
- Optional ROV operated valve for flow monitoring on 36".
- Sliding sleeve is replaceable.
- Guidelineless.
- Can run 16" sub-mudline or in 18-3/4" housing.

Advantages

- Testable 26" sub-mudline hanger.
- Uses standard 18-3/4" HP housing with bushing.
- Allows mechanical control of flow during cement transition.
- Option to eliminate 26" does not require any additional equipment.
- Reduced wellhead stackup.
- If optional ball valve is used, shallow flow pressure build-up can be monitored.

Disadvantages

- Requires special G&A or GRA for stripping over sleeve.
- Requires modified 36" housing.

SHALLOW WATER FLOW CONTROL

36", 30", 26", 20" w/ 20" bml csg. hgr. and packoffs
18 3/4" HP hsg. ran and stab into 20" hgr.

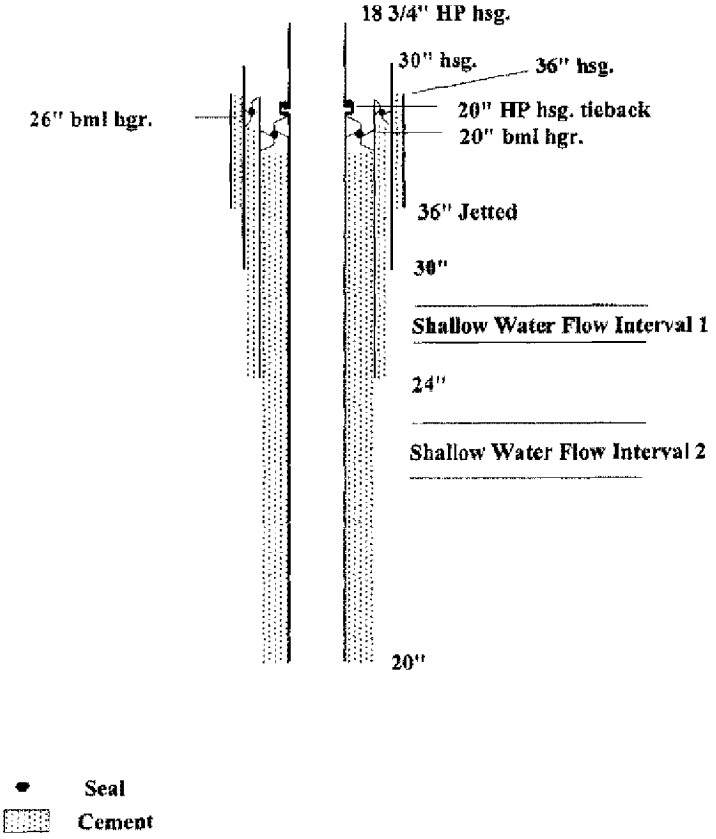

Figure 1-13 SWF Concept 11: 36", 30", 26", 20" w/ 20" bml csg. hgr. and packoffs 18-3/4" HP hsg. run and stab into 20" hgr.

Concept

1. Jet in 36".
2. Drill conductor hole.
3. Run 30" to just above first shallow flow interval on 30" housing and cement.
4. Drill through Shallow Flow Interval 1 with or without pin connector and 26" riser.
5. Pull riser if run.
6. Run and cement 24"/26" across zone on 26" mudline hanger with seal.
7. Drill through Shallow Flow Interval 2 with or without riser and pin connector.
8. Run 20" on sub-mudline hanger with or without riser. Run 18-3/4" housing into 20" mudline hanger with elastomeric seal.
9. Allows shut off of SWF Interval 1 via sub-mudline seal and 30" shoe gives integrity to prevent broaching.
10. Allows shut off of interval 2 via 20" sub-mudline seal and 24" shoe provides integrity to prevent broaching.
11. Used for development location.

Features

- 36" x 30" x 24" x 20".
- Development design.
- 30" intermediate wellhead housing with sub-wellhead landing shoulder.
- 26" sub-mudline hanger and 24"/26" cover first zone with seal to 30" sub with elastomeric or metal to metal seal (if packoff is used, it is testable and replaceable).
- Sub-mudline 20" hanger land and seals in 26" sub with elastomeric or metal to metal seals which are testable with or without riser.
- Uses split 20" string with 20" primary string run through 26" riser latched to 30" intermediate housing.
- 18-3/4" housing lands into primary string and seals with elastomeric seals and is retrievable and re-installable in seal leak event.
- Can use guideline or guidelineless equipment.

Advantages

- Provides four strings through shallow flow interval.
- Allows 20" to be run through flow part of the zone with or without riser control.
- High reliability on 26" x 30" and 20" x 26" annuli which are replaceable and testable without riser.

Disadvantages

- Increased inventory.
- Complicated.
- 26" riser expense if used.

- If 26" riser is used, broaching of 30" can occur.
- Has an additional intermediary seal in 20" string below 18-3/4" housing which requires additional trip to set 18-3/4" housing.
- Pre-loading of 18-3/4" x 30" requires boot strap tool run.

SHALLOW WATER FLOW CONTROL

38", 26", 20" w/ 18 3/4" HP hsg.

w/ shut off sleeve on 38" hsg. or
18 3/4" tieback to 20" sub-mudline 20" csg. hgr. option

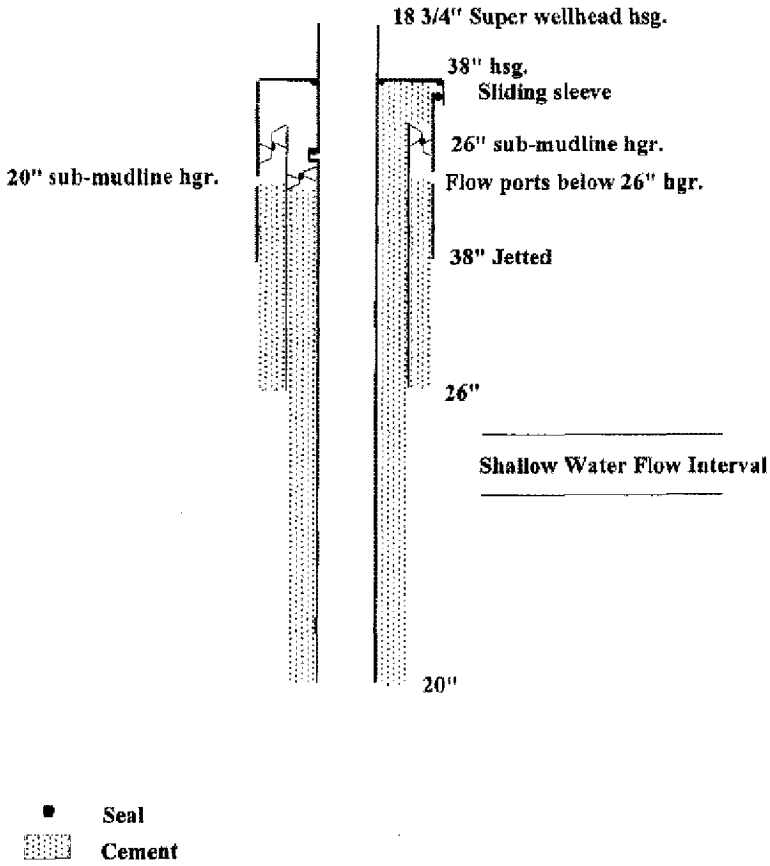

Figure 1-14 SWF Concept 12: 38", 26", 20" w/ 18-3/4" HP hsg. w/ shut off sleeve on 38" hsg. or 18-3/4" tieback to 20" sub-mudline 20" csg. hgr. option.

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Concept

1. Jet 38" with 26" sub-mudline landing shoulder and sliding sleeve on 38" housing.
2. Drill conductor hole with or without riser and pin connector.
3. Pull riser if run.
4. Run 26" above flow zone with sub-mudline hanger and seal. Cement without picking up hanger and taking returns through lower ports on 38" housing.
5. Run 20" across zone on 18-3/4" Super wellhead housing which seals in 26" housing.
6. Sliding sleeve on 38" housing activated with 18-3/4" housing running tool after cementing.
7. Allows shut off of zone via sliding sleeve which shuts off 26" x 20" annulus and 26" shoe provides integrity to prevent broaching.
8. Alternatively, set 20" sub-mudline and tieback 18-3/4" to 20" sub-mudline casing hanger with elastomeric seals.

Features

- 38" x 26" x 20".
- Super wellhead housing with high bending moment capability.
- 26" sub-mudline hanger can be metal to metal and re-installable, testable without riser
- Guidelineless or guideline application.
- Can use 20" sub-mudline casing hanger and tieback 18-3/4" housing with or without 26" riser. Does not require sleeve.
- 20" sub-mudline seal can be metal to metal and re-installable, testable without riser.
- Can run 16" sub-mudline or in 18-3/4" housing.

Advantages

- Testable 26" sub-mudline hanger.
- Super wellhead 18 3 /4" housing.
- Allows mechanical control of flow during cement transition.
- Option to eliminate 26" does not require any additional equipment.
- Picking up off 26" shoulder while cementing eliminated.

Disadvantages

- Requires special 38" guideline or guidelineless.
- Requires special 38" housing.

SHALLOW WATER FLOW CONTROL

38", 26", 20" w/ 18 3/4" Super Wellhead hsg.
w/ nested housings and ROV valve
18 3/4" tieback to 20" sub-mudline 20" csg. hgr. option
or 20" single string

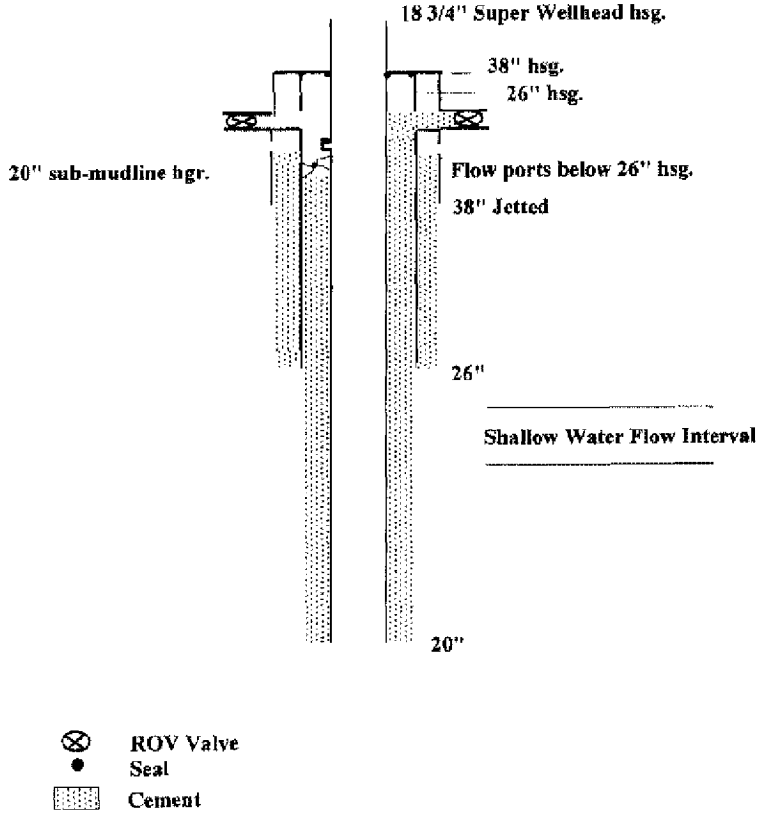


Figure 1-15 SWF Concept 13: 38", 26", 20" w/ 18-3/4" Super Wellhead hsg. w/ nested housings and ROV valve.

Concept

1. Jet 38" with 26" sub-mudline landing shoulder and ROV valve on 38" housing.
2. Drill conductor hole with or without riser and pin connector.
3. Pull riser if run.
4. Run 26" above flow zone on nested housing which seals in 38" housing.
5. Cement taking returns through lower ports on 38" housing.
6. Run 20" across zone on 18-3/4" Super wellhead housing 18-3/4" housing seals in 26" housing.
7. Allows shut off of zone via ROV valve 26" x 20" annulus and 26" shoe provides integrity to prevent broaching.
8. Alternatively, set 20" sub-mudline and tieback 18-3/4" to 20" sub-mudline, casing hanger with elastomeric seals.
9. ROV valve available for monitoring.

Features

- 38" x 26" x 20" nested housings.
- Super wellhead housing with high bending moment capability.
- Guidelineless or guideline application.
- Can use 20" sub-mudline casing hanger and tieback 18-3/4" housing with or without 26" riser.
- Does not require valve but valve can be provided to give option to run full string or monitoring of annulus.
- 20" sub-mudline, seal can be metal to metal and re-installable, testable without riser.

Advantages

- Super wellhead 18-3/4" housing.
- Allows mechanical control of flow during cement transition.

Disadvantages

- Requires special 38" guideline or guidelineless equipment.
- Requires special 38" housing.
- Option to eliminate 26" would require bushing or dummy housing.

1.2.5 Remedial Operations and P&A Concerns

Once shallow flow has initiated behind pipe, it is usually very difficult to stop. The general approach is to stop the flow temporarily and then cement for long term control.

SWF behind pipe is difficult to stop

Identification of the flow interval and pressure is important. If logging while drilling data is not available it will be necessary to run temperature, noise logs, or thermal decay logs to determine flow interval. However, this data may be very difficult to interpret and some experience has shown the only the only reliable source of prediction is the thermal decay log.

Once the interval location is determined, operations can proceed to stop the flow. If the flow in behind pipe, usually this requires perforating the casing, setting of an cement retainer for control, and pumping kill mud on the back side of the casing.

Stopping SWF flow:
- **Locate flow**
- **Perforate casing**
- **Set cement retainer**
- **Pump kill mud**

Once the flow has stopped, cement is pumped to seal off the annulus. Various types of cement have been used such as diesel oil cement with synthetic fluid for base oil, standard, and right angle set cement.

SWF may create alternate flowpath after cementing

However, in most cases the annulus area is very difficult to cement due to its size and requires high placement rates. Also, any additional pumping enlarges the disturbed area. Very often after cementing the flow creates an alternate path to the mudline. Flow has been found to broach as far as several hundreds of feet from the wellhead.

1.3 Drilling Fluid Considerations

1.3.1 Summary

This section addresses issues affecting drilling fluids management in the deepwater drilling environment, including the following main areas:

- Pore pressure/fracture gradient
- Storage capacities on the rig
- Using oil-base mud vs synthetic-base mud
- Operational considerations related to drilling fluids

1.3.2 Pore Pressure/Fracture Gradient-Low Effective Stress

1.3.2.1 Thin margins

A thin margin between pore pressure and fracture gradient occurs due to the increased hydrostatic pressure when using a mud density greater than the density of seawater. The hydrostatic pressure on the formation is applied by the full column of drilling fluid back to the drilling rig.

Frac gradients much less than at corresponding BML depths in shallow water

The fracture gradient resulting from the overburden of the sediments is generated by sediment densities greater than seawater hydrostatic only below the mudline. This results in the fracture gradient, in equivalent mud weight terms, being much less than for corresponding depths below the mudline in shallower water.

Efforts to prevent exceeding the fracture gradient are even more important in deepwater drilling operations. The following drilling practices prevent exceeding fracture gradient:

- Control drilling to limit cuttings loading and increasing equivalent circulating density

- Use of Pressure While Drilling tools (PWD) to monitor downhole ECD and make real time decisions
- Careful attention to prevention of surge pressures during trips
- Better pore pressure prediction to prevent kicks
- Better pit level and flow monitoring to reduce kick size and to reduce circulating pressures at the exposed shoe during well control operations

1.3.2.2 Riser Margin

A riser margin is defined as the additional mud weight (MW) added below the mud line (BML) to compensate for the differential pressure between the mud in the riser and seawater in the event of a riser disconnect. Drilling operations with a subsea BOP and drilling riser in deep water usually do not have the ability to drill with a riser margin. Fluid circulation during typical floating drilling operations with the drilling riser installed provides a column of drilling fluid from the rig flowline level to the total depth of the well.

Drilling operations with a subsea BOP and drilling riser in deep water usually do not have the ability to drill with a riser margin

Primary well control is provided by the hydrostatic pressure of a column of drilling fluid that is greater than the formation pressures. Insufficient pressure in the wellbore may allow an influx of formation fluids to enter the wellbore from permeable formations. The MW and drilling practices must be managed to prevent an influx.

The hydrostatic pressure of the column of drilling fluid and the equivalent circulating density (ECD) must also be maintained at less than the fracture gradient of the exposed formations of the open hole. Fracture gradients are a function of the overburden pressures of the formations and the seawater column. Excessive MW or ECD may result in a loss of drilling fluids to the formation, possibly leading to reduction in the height of the column of drilling fluid, which reduces the hydrostatic pressure, possibly resulting in an influx from other parts of the wellbore.

Normal formation pressure is defined as pore pressure equivalent to a hydrostatic column of salt water. Abnormal formation pressures, i.e. equivalent pore pressures greater

than that of a column of salt water, are prevalent in the Gulf of Mexico and often at other locations around the world. Sometimes, the transition of the formation pressure from normal to abnormal occurs at a shallow depth below the mudline (BML). Further, formation fracture pressures and the associated fracture gradients (FG) are low as a result of the low density of the seawater contribution to overburden in deepwater, and often are further reduced by geologically young formations in many deepwater basins.

If a riser margin were maintained, density required to prevent an influx would exceed the FG of the casing shoe, resulting in lost circulation

In the Gulf of Mexico, the relationship of the abnormal pore pressures and low fracture gradients in many wells in water depths greater than those accessible to jack-ups (about 350ft), and, with a few exceptions, virtually all wells beyond about 1000ft of water, do not allow for a riser margin. In such cases, the MW sufficient to prevent formation influx has to be raised when drilling even a short distance below each casing string in the Gulf of Mexico. If a riser margin were to be maintained, the required density to prevent an influx would exceed the FG of the casing shoe, resulting in lost circulation. One option is to install an additional casing string when the density is raised to within the FG of the previous casing shoe while maintaining a riser margin. However, the number of casing strings needed would quickly compromise the ability to drill the depths needed to explore for or produce the hydrocarbon resources.

The number of casing strings needed would quickly compromise the ability to drill the depths needed to explore for or produce the hydrocarbon resources

An emerging technology described as dual gradient drilling, utilizing a subsea mud pump or other means to lift from the seabed to the rig at the surface, will be able to provide a riser margin. The subsea mudlift removes the hydrostatic pressure of the mud above the mudline, allowing only the hydrostatic pressure of the seawater column on the well. The resulting MW to be used BML will be sufficient to prevent influxes and prevent losses in long open hole intervals. This not only reduces the duration and cost of the drilling operation by reducing multiple casing strings, but also allows drilling with a riser margin and reduces the risk of formation fluid influxes and lost circulation.

Another emerging technology, expandable tubulars, can increase the number of available casing strings by one or two, perhaps more in the longer range. Expandable pipe liners have now had several successful field runs. Current development efforts are to establish operational reliability and to apply the method to various pipe sizes.

Until new technologies are available and reliable, the proven safe practices currently employed to drill without a riser margin can continue to provide safe and efficient floating drilling operations. The wellbore integrity will be maintained by the primary means of well control as a result of the drilling fluid column and backed by the secondary means of well control provided by the tested subsea BOP equipment. Good drilling practices and proper management of the primary and secondary well control systems will provide safe operations.

1.3.2.3 Losses, fracture propagation

Matrix strength and fracture propagation

Once formation fracturing has begun, it is difficult to stop. Again as water depth and water pressure increase, shallow formations do not develop matrix strengths and fracture propagation is difficult to stop. Keeping wellbore pressures as close to pore pressures as possible is the key to managing fracture propagation.

Problems with oil-based mud and synthetic-based mud

Oil base mud (OBM) and synthetic base mud (SBM) cause fracturing to be more severe and more difficult to limit. The fluids penetrate the fracture tips more readily and wet the formation with oil or synthetic base so that it is difficult to "heal" and re-develop formation strength. Water base muds may be preferred when fracture losses or fracture propagation is a persistent problem.

1.3.2.4 Ballooning

Ballooning is a term often used to describe the physical phenomena where drilling fluid is lost while circulating and then regained when the pumps are turned off. Opening and closing of induced or in-situ micro fractures can explain the fundamental mechanism behind this phenomenon.

Ballooning mechanism

The fundamental mechanism for ballooning or opening/closing of fractures while drilling is fracture initiation and/or propagation. When the bottom hole pressure (ECD) exceeds or equals the fracture propagation pressure (FPP), a stable radial fracture is propagated.

Stable radial fracture propagation

When the pumps are turned off, the ECD falls below the FPP, and the in-situ horizontal stress forces the fracture to close. The closing of the fracture pushes the mud back into the wellbore. Thus some volume of mud is lost every time the ECD exceeds the FPP, and then regained when the pressure drops below FPP as long as there is a stable radial fracture propagation.

If the ECD exceeds the FPP sufficiently, fracture propagation becomes unstable and the result is a large fracture extension and massive mud losses.

Another perception regarding ballooning is that hydrostatic overbalance creates an enlarged wellbore. Typical movement of the wellbore wall may be no more than 1/4-in to 1/2-in. These conditions can result in the well flowing back fluid when the pumps are stopped and the ECD removed. It is questionable whether this phenomenon is actually occurring since the ballooning volumes do not increase linearly with increasing depth.

1.3.2.5 Equivalent circulating densities

Numerous casing strings

The equivalent circulating density (ECD) is a very significant problem in deepwater drilling as the ECD further reduces the margin between the fracture gradient and the mud weight. This results in setting numerous casing strings with frequent short casing intervals.

Temperature effects on oil-based, synthetic muds

The effects of cold temperature and compressibility on OBM and SBM further compound ECD and density uncertainty. True viscosity, pressure loss, and density are difficult to estimate accurately. OBM/SBM fluids are very temperature sensitive and the effect of thermal thinning and thickening on viscosity is pronounced. In addition, many SBM base oils have a higher viscosity than traditional OBMs, which increases ECD problems.

1.3.2.6 Gas solubility (OBM/SBM)

The solubility of gas in OBM/SBM is dependent on the chemical composition of the gas/oil, pressure, and temperature. The volume change associated with gas going into solution is also a function of the gas/oil ratio of the influx.

Kick indicators with OBM/SBM

Kick indicators such as pit gain or flow will not be as pronounced when drilling with an OBM/SBM fluid compared to a water based mud.

The amount of gas that goes into solution for an OBM/SBM fluid is a function of the saturation point for a given temperature and pressure. The gas will remain in solution until it is no longer at its natural temperature and pressure. The quantity of the gas and depth it breaks out also depends on the gas/oil ratio.

1.3.2.7 Leak-off testing with OBM/SBM (vs WBM)

Leak-off testing with OBM/SBM is a more critical operation as compared to testing with water-based mud.

Choke response may be delayed at bottom hole

If the formation is taken to break down where OBM/SBM fluid is injected into the formation, the formation may not heal and regain full fracture resistant strength. If the last cement job is not competent and OBM/SBM is pumped into the annular cemented region, it will be difficult to achieve a competent remedial cement bond.

Perform leak-off testing with water-based mud prior to displacing with OBM or SBM

It is usually preferred to perform leak-off testing with WBM, if possible, prior to displacing to an OBM/SBM. Experience has shown that the leak-off values (and subsequent fracture pressures) obtained with WBM will be higher than those obtained with OBM/SBM. Reported values for this difference are in the 0.5 to 0.7 lb/gal range. In addition OBM/SBM makes an excellent fracturing fluid and more easily leads to a fracture and fracture propagation.

1.3.2.8 Fluid compressibility (OBM/SBM)

Fluid compressibility is a chief concern for OBM/SBM fluids as it affects not only density but also may cause flow gains/losses during transience. The effect of the local high pressure and lower formation temperatures makes fluid compressibility for OBM/SBM more of a concern in deepwater, as compared to shelf and land drilling where the effects of temperature (expansion) and pressure (compressibility) generally cancel each other out.

Fluid compressibility affects density, may cause gains/losses

OBM/SBM gain density as the effect of higher pressure in increasing water depth locations and deeper well drilling becoming more common.

Choke Response (OBM/SBM)

OBM/SBM fluids exhibit complex fluid behavior due to compressibility, pressure transmission, and gel strengths. Therefore, the opening and closing of the choke located on the seafloor does not result in an instantaneous increase/decrease in pressure at the bottom of the hole or in the pressures detected at the surface. This time delay behavior needs to be understood and compensated for.

Flow after Pumps Are Stopped

A common condition in deepwater drilling is flow after the pumps are stopped. There can be a number of causes for this including an underbalanced formation fluid kicking, an overbalanced formation ballooning or elastic fracture (opening/closing), plus fluid thermal expansion, rig heave, and fluid momentum. This symptom should be measured and recorded in a systematic manner to insure the safe control of the well and the proper response.

1.3.2.9 Downhole measurements (PWD)

PWD improves predictions of surge/swab pressures

Pressure while drilling (PWD) measurements are especially helpful in narrow pore pressure/fracture gradient situations with low effective stress formations. These measurements allow the true ECD to be known so that a sufficient margin can be used to prevent fracturing the formation and inducing lost circulation. Utilizing PWD data to correlate and calibrate a computer model of the drilling fluid behavior will allow more accurate predictions of surge and swab pressures when not circulating (when PWD data is not available).

1.3.3 Storage Capacities on Rig

1.3.3.1 Riser storage (for emergency disconnect)

A sufficient volume of pit space must be kept in reserve so that the drilling fluid from the riser can be immediately displaced and recovered for future use. This riser storage volume should be equal to the riser capacity plus 200 barrels excess for surface pumping and line losses.

1.3.3.2 Brine storage (salt saturated systems)

When utilizing salt water muds it is preferred to use liquid brine rather than mixing dry salt. Keeping 25-35% of the active system volume in liquid brine is helpful in mixing and utilizing pre-mixed concentrate for dilution.

Many deepwater rigs have a limited brine storage area and this quantity may not be feasible. Most often brine is diluted with drill water then prehydrated bentonite or polymers are added with other chemcials and blended into the active system for dilution. This method prevents a wide fluctuation in drilling fluid properties and keeps drill solids under control. Even when using OBM/SBM it is recommended to have $CaCl_2$ brine storage, so that sacked salt will not be required.

Mixing dry salt requires huge quantities of drill water

The alternative to using brine is mixing dry salt with drill water. When using drill water and dry salt, enormous quantities of drill water are required, putting a burden on work boats delivering drill water or water-making units.

Seawater calcium, magnesium create adverse effects

If seawater is used with dry salt, the calcium and magnesium from the seawater complicate the treatment and performance of the drilling fluid products: clays and polymers. Dry salt is time and labor intensive. Using brine is preferred.

1.3.3.3 Base oil storage

When oil or synthetic fluids are being used, a sufficient quantity of base liquid should be stored on board. It is desirable to have 25-35% of the active system volume in base liquid storage. Many deepwater rigs have a limited base liquid storage area and this quantity may not be feasible.

The base liquid is used to make up for hole volume and mud losses on cuttings. In addition, if lost circulation occurs, base liquid can be used to build new volume until the supply boats can resupply.

1.3.3.4 OBM/SBM discharge regulations

Cuttings containers and liquid volume storage used when normal discharge procedures are not acceptable

When using OBM or SBM, contingencies should be developed for collecting and storing both liquids and cuttings in the event that a situation occurs where they can not be discharged or handled in a normal manner.

Sufficient storage for cuttings containers and liquid volume should be arranged. Many deepwater rigs have a limited storage area and this may not be feasible.

1.3.3.5 Planned disconnect with OBM/SBM

Plans and procedures should be developed for displacing and storing the mud from the riser during disconnects with OBM/SBM. Either a sufficient flow rate of seawater from the sea or seawater from storage (equal to riser volume plus 200 bbl) should be available so that this displacement can be done quickly and effectively.

1.3.3.6 Weighted systems for shallow water flow kill

See also Well Control Procedures, 2.8, Well Control Prior to BOP Installation/SWF

Kill weight mud of ± 12.0 ppg has historically been spotted into open hole prior to running 20" conductor casing. In the case of shallow water flows (SWF), mud weight may need to be adjusted to prevent flow prior to pulling out to run casing. In all cases, the kill weight fluid should not have a density that exceeds fracture pressure.

Drilling with weighted mud, returns to seafloor

Weighted mud can be utilized to drill the 20" hole section taking returns to the seafloor to prevent shallow water flow and associated sand flow. This will pose operational considerations for kill mud volumes, i.e., a moored barge or deck tanks for mud storage.

A common practice is to have heavier mud weight prepared and cut the density to the desired kill mud density on-the-fly. Once the kill mud weight is introduced to the wellbore for a shallow water flow, hydrostatic pressure should be maintained throughout the cementing process.

1.3.3.7 Barite storage/mixing capacities and rate

Barite storage is limited on most deepwater rigs due to deck loads, cement storage, and tankage. A minimum quantity of

barite would be equal to that required by the MMS or enough barite to weight up the entire mud system 1 ppg.

1000 bbls of new mud every 8 hours

With such large system volume when drilling in ultradeep waters, the barite requirement alone stresses storage tankage capacity. The number of mixing pits, mixing pumps, mixing hoppers, barite delivery systems and manifold piping should be sufficient to mix mud products both in the circulating system and while building new volume in a reserve pit simultaneously, or to mix in two reserve pits simultaneously. These systems and manpower capabilities should be sufficient to mix and build 1000 bbl of new mud every 8 hours.

1.3.3.8 Kill weight mud: built on rig or delivered from offsite

Unweighted or partially weighted base muds

Kill weight mud is required and is most often built or at least weighted on the rig. Many deepwater mud engineers prefer to order out and use partially weighted base muds (both OBM/SBM or WBM) to build kill mud. By using unweighted base muds, barite settling in the supply boat is not a concern and a greater volume of mud can be sent to the rig. This shifts a large part of the mud mixing workload to the more efficient more accessible shore base facility.

MMS requirements for mud and mud materials inventory at rigsite

The MMS CFR 250.60.d states the following regarding mud quantities:

1. Quantities of mud and mud materials at the drill site shall be utilized, maintained and replenished as necessary to ensure well control. Those quantities shall be based on known or anticipated drilling conditions to be encountered, rig storage capacity, weather conditions, and estimated time for delivery.

2. Daily inventories of mud and mud material including weight materials and additives at the drill site shall be recorded and those records maintained at the well site.

3. Drilling operations shall be suspended in the absence of sufficient quantities of mud and mud materials to maintain well control.

Minimum barite and gel inventories

Operators are required in the Application to Drill to state minimum barite and gel inventories on the rig while drilling operations are underway. This is usually based on rig storage capacities and transportation times. The onsite operator representative must understand the basis of this minimum inventory.

1.3.3.9 LCM effectiveness/considerations with OBM/SBM

Selecting lost circulation material (LCM)

There are a number of issues which relate to selecting an appropriate lost circulation material (LCM) when drilling in deepwater, the first being the size restriction normally placed on what is used due to MWD/LWD tools and/or mud motors.

"Fine" may be too large

These tools generally require LCM which is granular and sized in the "fine" category. Keep in mind that there is no standard with regard to what sizes are called fine, medium, or coarse within the drilling industry. One fine material may be in fact too large for a given tool.

Ground nut shells are generally recommended by the manufacturers of these tools and most fine ground nut shells have a median particle size in the 200 to 350 micron range. Other acceptable materials (to pass through tools) are listed below:

- medium to coarse sized calcium carbonate (in the 50 to 150 micron size)
- medium to coarse ground graphite materials
- ground cellulose type materials which are often used for drilling depleted sands (may not be effective in deepwater drilling)

For seepage losses with OBM, asphaltic, gilsonite, and amine-lignite type additives are appropriate.

Medium to coarse granular materials have been reported to stop fracture propagation through fracture tip screen out, making them the most effective materials for stopping lost circulation. Aside from this phenomena generally a blend of granular, flaked, and fiberous materials is most effective.

Highly absorbent LCMs (cellulose, paper) may cause OBM/SBM instability

May reduce amount of emulsifier, increase viscosity

OBM/SBM also may become quite viscous and possibly unstable when a highly absorbent LCM like fine ground cellulose and paper is used. Cellophane has been reported to cause instability also. These materials tend to reduce the amount of emulsifiers and wetting agents which are available to the emulsion, and they soak up a large amount of the available continuous phase, both actions which result in increases in viscosity.

With SBM, it is generally not acceptable to use organic hydrocarbon type materials like asphalt or gilsonite. Therefore another granular material or amine lignite would be suggested for seepage losses.

1.3.3.10 Gunk squeezes/barite plugs

Reverse gunk squeezes

OBM/SBM lost circulation situations have been corrected with reactive plug slurries like reverse gunk and modified reverse gunk squeezes. Cementing companies usually provide these formulations. In general, lost circulation with OBM/SBM is more difficult to restore than with WBM. Displacing to a WBM may be considered in this situation.

Gunk squeezes are used for severe lost circulation

Gunk squeezes are special fluids for severe lost circulation, and are composed of bentonite in diesel oil or synthetic fluid. When squeezed, the mud will contact water in the loss zone and gel up severely to prevent further losses. A reverse concept of this may be applied when drilling with a non-aqueous system by using organophilic clay dispersed in water to seal off a thief zone.

Bentonite in oil or synthetic fluid forms gunk squeeze

Organophilic clay in water forms gunk squeeze

There is not an exact amount of clay prescribed for these squeezes, but typically 200 to 400 pounds of clay per barrel is used. In fresh water it is useful to add about 1 to 2 lbs/bbl of caustic soda and 4 lbs/bbl of lignosulfonate to assist in the dispersion of the organophilic clay.

The squeeze procedure is similar to other squeeze applications. A spacer is normally placed between the gunk material and the drilling fluid.

Squeezes may be formulated with cement

Gunk squeezes may be formulated with cement if desired for additional consistency where severe and total loss is encountered. The recommended concentration is about 200 to 250 lbs/bbl of cement. Use of a 5 to 10 barrel non-aqueous spacer ahead and behind the slurry is also suggested.

1.3.4 Utilizing OBM/SBM

1.3.4.1 Discharge: environmental/regulatory impact

Discharge of OBM results in a violation of discharge regulations. SBM apparently can be discharged subject to regulations that cover other fluids which pass the LC50 test and sheen regulations.

1.3.4.2 Allowable brine weights (hydrate control)

Elevated salt levels and hydrate formation

When drilling with WBM, high salt concentrations are used to prevent gas hydrates. When drilling shallow intervals the pore pressure and fracture gradient do not allow a sufficiently high salt content due to the increased density which would result in lost circulation. Elevated salt levels are however still recommended even though total protection is not provided. This lessens the chance of hydrates forming and increases the time required for them to form.

Hydrate inhibitive fluid

In these situations, contingency plans for BOP choke and kill line displacement with a hydrate inhibitive fluid should be made. Low molecular weight glycol (propylene glycol and ethylene glycol) and glycerin additives can be used to achieve gas hydrate inhibition at a density less than salt saturated.

1.3.5 Operational Considerations for Using OBM/SBM

1.3.5.1 Solubility

Most formation gases are soluble (as both liquids and gases) in refined oils and synthetic fluids. These oil and synthetic soluble gases include methane, typical natural gasses, carbon dioxide, and hydrogen sulfide. These gases have minimal solubility in water base muds and brines.

Gas solubility causes major concerns with regard to kick detection and gas expansion during circulating out a kick. Utilizing equipment with the ability to detect small kicks is essential when using OBM/SBM fluids. As the solubilized gas and OBM/SBM are circulated from the well, the pressure is reduced to below the bubble point and a rapid increase in fluid volume and flow occur during the last 1,000 ft or so below the rig.

1.3.5.2 Compressibility

Fluid compressibility is a major concern for OBM/SBM fluids as it affects not only density but also may cause flows gains/losses during transience. The effects of the local high pressure and lower formation temperatures makes fluid compressibility for OBM/SBM more of a concern in deepwater, unlike shelf and land drilling where the effects of temperature (expansion) and pressure (compressibility) generally cancel each other out.

Effects of higher pressure in increasing water depths and deeper wells

OBM/SBM gains density due to higher pressure resulting from deepwater locations and deeper well drilling. Compressibility is also related to a pressure transmission phenomena where some time is required to overcome gels and transmit induced pressure through the well.

1.3.5.3 Flow checks

Flow checks should be made at drilling breaks and prior to all trips. A record should be made of any flows with the pumps off, including the volume of mud and the length of time it flows. This will help in determining if and when either ballooning or kicks are occurring.

1.3.5.4 Margins

Increasing water depth has the effect of decreasing the margin between pore pressure and fracture gradient, causing a thin margin in operating mud weights. Lost circulation may occur at a mud weight equal to the pore pressure after circulating pressure losses act on the formation. In addition, any reduction in mud weight below

pore pressure will cause a water flow and kick due to the highly water saturated formations

A reduction in offshore overburden gradient will dramatically decrease the fracture gradient, particularly in deepwater locations and shallow well depth. The fracture gradients are more critical as water depth increases. An offshore well with an air gap of 100 feet in 1000 feet of water has a fracture gradient of 15.3 ppg, whereas a well in 4000 feet of water will have a fracture gradient of 12.3 ppg. These conditions require the use of good drilling practices to prevent surge, swab, and breaking circulation pressures from causing fracturing, lost circulation or kicks.

1.3.5.5 Temperature stability

Mud stability is affected by downhole and mudline temperatures

The temperature stability of a drilling fluid is critical to accomplishing the desired functions of the fluid and preventing problems. For deepwater applications, the fluid must exhibit reasonably stable properties not only at downhole maximum temperatures (frequently 250 - 300 degrees F) but also at mud line minimum temperatures (frequently at 36 – 42 degrees F).

The dynamic behavior of the drilling fluid should be understood and a computer model of its steady state and transient behavior should be available to estimate ECDs, hole cleaning capabilities, and potential pressure losses. When breaking circulation and warming up the mud system it is important to consider the higher viscosity and possibly circulate at a lower pump rate for a few circulations.

1.3.5.6 Mud properties

Mud properties must be selected which will allow the well to be drilled and kept stable under a wide range of conditions. The mud engineer will need to make special measurements of cold temperature viscosity and to utilize preplanning to keep the optimum mud properties for the fast and expensive drilling operation.

Breaking Circulation

Breaking circulation is a critical operation in deepwater locations as the narrow fracture margins make lost circulation a constant threat. It is recommended to break circulation slowly, rotate and pick up the pipe slowly while kicking in the pump. For many situations it is advisable to stage in the hole and break circulation and circulate fresh mud to the riser.

Low pump rates and cuttings concentrations

Even after breaking circulation, the pump rate and cuttings concentration in the annulus with OBM/SBM may need to kept down until the mud warms up.

Tripping Speeds

Tripping speeds in and out of the hole must be modeled based on hole and drillstring geometry, and mud properties. Considerations for low fracture gradients and highest exposed pore pressure must be considered.

Computer Modeling

Modeling of flow behavior and its associated frictional pressure losses is essential for predicting ECD, nozzle size selection, bit hydraulics, anticipated standpipe pressure and pump liner requirements.

1.3.5.7 Kick detection

Limiting the volume of influx with low fracture gradients exposed will allow conventional well control procedures to be conducted. Large influx volumes will most likely result in underground flows.

Mud Logging

The role of the mud logging personnel and equipment is more important in deepwater operations. Pore pressure

must be properly estimated and changes made to mud density to reduce kicks.

Flow Detection on Floating Rigs

Care must be taken to implement the most accurate flow detection devices available. The first warning sign is an increase in flow. Due to large surface volumes, pit level device accuracy may not be adequate for identifying and limiting influx volumes.

1.3.6 General Considerations

1.3.6.1 *Hydrate prevention*

See also *Well Planning, 1.4, Hydrates*

Well Control Procedures, 2.7, Hydrate Prevention/Removal

Hydrates are a naturally occurring solid composed of gas and water. Hydrates tend to form in water base fluids at higher pressures and lower temperatures.

Hydrates interfere with well control procedures

With the right combination of gas entrained in the drilling fluid, hydrates can form as the fluid cools while circulating up the wellbore, forming an ice-like substance. Hydates can plug the choke and kill lines, BOPs, and riser, interfering with well control procedures. Typical sea floor temperatures and densities in deepwater drilling are sufficient to cause problems with hydrates to occur.

Hydrate inhibitors: salt, alcohols, glycols, glycerols

Prevention of hydrate formation has been limited to increasing chloride content with salt additions, or adding alcohols, glycols, and glycerols. The industry is continuing to develop special chemical inhibitors to add to the mud to interrupt the formation of hydrates.

To date, the most effective deterrent to the formation of hydrates is the use of increased chlorides up to 180,000 mg/l chlorides. Also useful is the practice of spotting glycol or glycerol in the BOPs while shut-in. Accurate software is available to predict the occurrence of hydrates using sea floor temperatures and pressure.

1.3.6.2 Barite plugs

Barite and hematite plugs are an effective means to seal off sections of the borehole experiencing influx of fluids. They are used in situations where weak zones overlie the intrusive section, and a heavy weighted pill is needed to prevent further influx.

The following factors affect the density of the plug and the rate of settling:

- specific gravity of the weight material
- freshness of the water
- pH of the slurry
- concentration of deflocculant

Slurry density is most important factor in barite/hematite plug

The most important of these is the density of the slurry. If the fluid is too heavy the weight material particles will interfere with each other and restrict settling. Therefore, for barite the upper density limit is 16.0 ppg, and hematite is normally 18.0 ppg. This will assure a tight and quick forming pack.

In addition to the weight material, the slurry should be treated with caustic soda to increase the pH to 9.0 to 10.0, and approximately 2.0 lbs/bbl of lignosulfonate is needed to thin the slurry. A small concentration of a thinning phosphate such as SAAP may also be used.

Barite plugs may also be formulated with non-aqueous fluids, but a wetting agent will be need to assure that the weight material is totally oil wet.

The length of the plug should be determined by the severity of the intrusion, and the point of the loss zone.

The plug length (L) may be calculated as follows:

$$L = \frac{\text{sx of weight material}}{\text{S.G. x VR x 3.5}}$$

where:

L = Length of settled plug, ft
sx = number of sacks of weight material
S.G. = specific gravity of the weight material
VR = Volume /ft hole

1.3.6.3 Spacers

The use of spacers to separate two incompatible fluids during displacement fall into two general categories. The first is displacement of one drilling fluid to another. The second refers to a clean fluid, typically used for completion, displaced into the wellbore behind a drilling fluid. The latter requires that the hole be clean and clear of any dirty material that might interfere with the completion process.

Condition for low viscosity

When circulating out a fluid it is helpful to take some time and effort to condition the fluid to have the lowest viscosity possible, so that the fluid may be efficiently removed.

Rotate and reciprocate drill pipe during displacement

The driller should rotate and reciprocate the pipe during the displacement. This assures that the sides of the wellbore will have better cleaning, and the fluids will not get strung out in the annulus, which creates intermingling.

Turbulent flow desirable

The flow rate should be increased to allow turbulent flow or as close to it as possible in order to flatten the profile for improved sweeping.

Spacer to cover 600 ft in annulus

Finally, the volume of spacer to be used should be sufficient to cover at least 600 feet in the annulus with the density of the displacing fluid equal to greater than the displaced fluid, if possible. If the two fluids are of uneven density, the higher density fluid should be used behind the lower density to improve hole displacement.

Displacing OBM/SBM with WBM

When displacing a non-aqueous fluid with a water base system, use a high viscosity spacer followed by viscous water preferably weighted, then followed by the water base mud. With a water base fluid being displaced by a non-aqueous fluid, use a spacer of water thickened with biopolymer, weighted, then followed by viscous oil fluid, then by the oil or non-aqueous mud.

When displacing a clean fluid into the well, great precaution must be taken to ensure the cleanliness of the wellbore. This may entail the use of scrapers and centralizers to remove the debris attached to the wall of the casing, as well as two or three wash solvents. Inspect all the tanks and hoses for cleanliness, as well.

Displacing water base fluid to clean completion fluid

For displacing a water base fluid to a clean completion fluid, four stages are suggested:

Stage	Description
1	Water (weighted if necessary) 2% surfactant 5 lbs_m/bbl caustic soda
2	Water with 2.5% dirt flocculent to continue to wash particles of gel
3	Viscosified water 2 lbs/bbl xanthan gum 2% water wetting agent (to completely water wet casing and tubing) Minimum 10 minute contact time in the annulus
4	Circulate and filter completion fluid for adequate clarity

Table 1- 7 Displacing WBM with completion fluid.

Displacing non-aqueous fluid to clean completion fluid

For displacing a non-aqueous fluid to a clean completion fluid, six stages are suggested:

Stage	Description
1	Pump 15 – 20 bbls of base fluid to be used as spacer before second stage
2	Viscosified water (weighted if needed) 2% surfactant Higher viscosity and density than the mud Minimum 10 minute contact time in the annulus
3	Non-weighted viscosified water 2% surfactant Viscosity 60 – 80 sec/qt Minimum 10 minute contact time in the annulus
4	Brine buffer to cover 800 ft of annulus between third and fifth stages
5	Brine spacer with wash surfactant
6	Circulate and filter completion fluid for adequate clarity

Table 1- 8 Displacing OBM/SBM with completion fluid.

1.3.6.4 LCM formulations

In general the formulations have been designed around severity of lost circulation problems, using smaller concentrations for the seepage loss situations, and larger, higher concentrations of materials for the more severe (total) loss problems.

Permeability is a guide for particle size with seepage loss

If seepage loss is the problem, size the particle using the square root of the permeability as a guide. For example if the sandstone has a permeability of 180 millidarcies, then the particle size of the cellulosic, carbonate or nut plug material should be 13 microns in diameter.

One-third rule

Another method to help size material is using the "one-third rule," which states the that a particle will obstruct an opening if the size of the particle is 1/3 or smaller than the pore throat it is attempting to plug. However a particle of 1/10 or smaller than the size of the opening will pass through with no ability to obstruct.

For seepage or minor losses, the procedure has been to treat the whole system and continue to drill. However, if the losses are more severe, the procedure is to add a concentration of LCM material to a pill of fluid, spot across from the loss zone, and allow it to seal for a period of time.

The slurry may be squeezed into the zone, if desired. If this appears to be successful, then repeat the operation with an increase in concentration or a change of mix. It is important to use a mixture of shapes and sizes in the spotting pills.

There is no set formulation, but some examples of pills that might be considered are as follows:

LCM Type	Seepage ppb	Moderate Loss ppb	Severe Loss ppb
Granular	5 – 10	10 – 15	20 - 25
Flake	5 – 10	5 – 10	10 - 15
Fibrous	0 – 5	10 – 15	15 - 20
Examples of LCM Types			
Granular	• Nut plug • Calcium carbonate • Graphite		
Flake	• Cellophane • Mica • Cottonseed hulls		
Fibrous	• Cellulose • Wood fiber • Pulverized formica		

Table 1- 9 Example LCM formulations.

In addition to the above, blends of the three shapes are available in one package and are very effective. For severe losses in fractured and vugular zones, mineral wool fiber is available and this is effective, although difficult to blend through the hopper. No more than 10 ppb concentration should be used of the mineral wool fiber.

1.4 Hydrates

See also *Well Planning, 1.3.6.1., Hydrate Prevention*

Well Control Procedures, 2.7, Hydrate Prevention and Removal

1.4.1 Summary

Hydrates form a lattice structure to entrap gas molecules

Hydrates are a well-recognized operational hazard in deepwater drilling. They belong to a group of substances known as clathrates (substances having a lattice-like structure or appearance in which molecules of one substance are completely enclosed within the crystal structure of another) and consist of host molecules (water) forming a lattice structure acting like a cage, to entrap guest molecules (gas).

Hydrates form at freezing temperatures under sufficient pressure

They can form in temperatures above 32° F under sufficient pressure, resemble dirty ice, are solid in nature and have a tendency to adhere to metal surfaces.

Awareness of potential for hydrate formation minimizes risk and expense

Natural gas molecules ranging from methane to isobutane, hydrogen sulfide and carbon dioxide are known to produce hydrates. They are generally very stable and normally do not pose any immediate threat to personnel, rig or environment. By incorporating an awareness and acceptance that an environment exists where hydrates may form, they can be safely dealt with, and the exposure to risk and expense can be minimized.

1.4.2 Requirements for Hydrate Formation

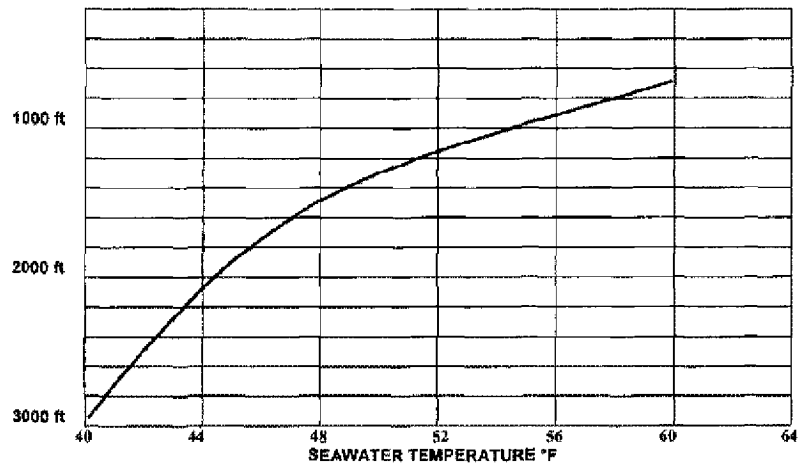
Hydrate formation is a function of pressure, temperature, gas composition and the aqueous phase composition. As deeper water environments are challenged, the potential for hydrate formation increases due to the combination of higher pressures and lower temperatures encountered.

1.4.2.1 Effects of temperature

Estimated temperatures in GOM:

- **60°F at 700 ft**
- **48°F at 1500 ft**
- **40°F at 3000 ft**

Figure 1-16 below shows the relationship of average seawater temperature as a function of water depth in the Gulf of Mexico. At 700 ft water depth, the average sea floor temperature in the Gulf of Mexico is approximately 60°F. It drops very quickly to approximately 48°F by 1500 ft water depth, then slows down and is approximately 40°F at 3000 ft water depth.

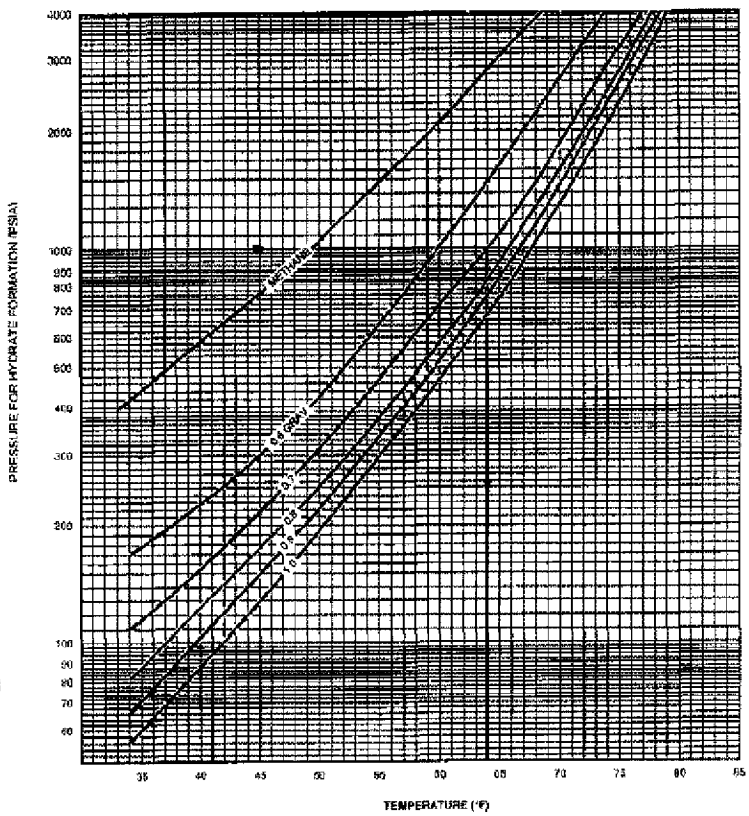


Barker, J. and R. Gomez, "Formation of Hydrates during Deepwater Drilling Operations," SPE/IADC 16130, 1987.

Figure 1-16 Relationship of average seawater temperature as a function of water depth in the Gulf of Mexico

1.4.2.2 Effects of specific gravity

Figure 1-17 below shows the effect of gas composition on hydrate formation. As the specific gravity of the associated gas increases so does the potential for hydrate formation. Phase behavior diagrams describe the physical state of any gas composition as a function of pressure and temperature. The points along this curve actually represent the temperature at which the last hydrate melts or dissociates at any given pressure.



Barker, J. and R. Gomez. "Formation of Hydrates during Deepwater Drilling Operations." SPE/IADC 16130, 1987.

Figure 1-17 The general principle of the effect of gas composition on hydrate formation.

1.4.2.3 Effects of supercooling

Figure 1-18 below shows that hydrates do not instantly form with favorable pressure and temperature as defined by their phase equilibrium curve; rather, some amount of supercooling (or overpressure) is required, typically 10-12°F, to initiate nucleation and experience growth.

Supercooling (10-12°F) required to initiate hydrate formation

This region below the dissociation phase equilibrium curve and above the supercooled curve (hydrate forming region) can be thought of as a safety factor for a given system if designed on the dissociation curve.

Yousif, M. "Minimizing the Risks of Hydrate Formation during Deepwater Drilling Operations." Controlling Hydrates, Paraffins and Asphaltines, New Orleans, 7 Nov 1997.

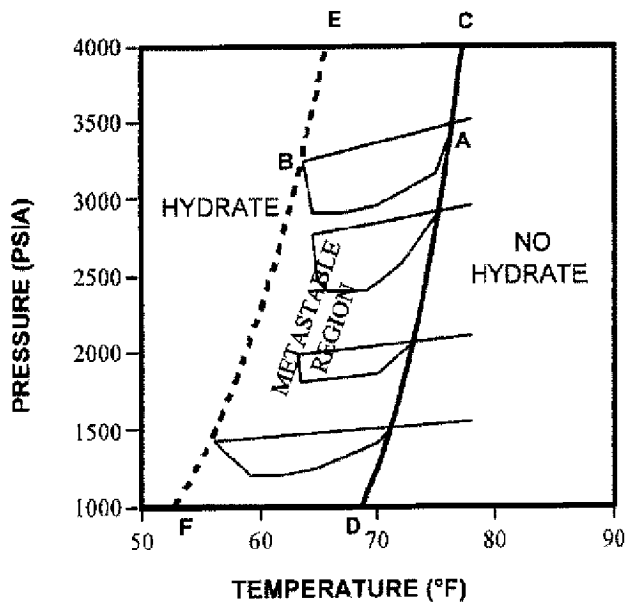


Figure 1-18 Results of a typical hydrate thermodynamic test.

A typical hydrate thermodynamic test generates the pressure-temperature (P-T) trace shown in Figure 1-18, where Point A represents the hydra equilibrium pressure

and temperature. In reality, Point A represents the pressure and temperature at which the last hydrate crystal has melted. By repeating this test at several different pressures, the entire hydrate phase line (CD) is generated. Along this line, the line phases gas, water, and hydrate edit in equilibrium. At any pressure and temperature conditions to the right of this line, hydrates cannot form, while to the left, they can.

A further examination of Figure 1-18 shows that during a thermodynamic test, hydrates actually form at Point B, as indicated by the massive pressure drop. Although hydrates actuallly form at Point B, the melting Point A is normally used to define the hydrate phase line. This is due to the metastability associated with the hyrate formation process, which does not allow a reproducible representation of fine hydrate formation locus EF.

Normally 10-12° F subcooling required to initiate the formation of hydrates

The dotted line EF represents the limit of the metastable region, where hydrate formation is possible. The metastable region reflects the degree of subcooling (normally 10-12°F) required to initiate the formation of hydrates. This subcooling can be looked at as a salty factor embedded in the way we estimate the potential for hydrate formation. The probability of hydrate formation increases as we move from line CD to line EF. In the region to the left at line EF, hydrate formation becomes definite.

Figure 1-19 below shows an enlargement of one specific point ("E") off the phase equilibrium curve from Figure 1-18 where hydrate nucleation, growth and decomposition are defined.

As water depth increases, it becomes necessary to operate below the dissociation curve, whereby the potential for the formation of hydrates becomes a function of time if favorable conditions present themselves.

Probability of hydrate formation increases as supercooled temperature is approached

The time required for hydrates to nucleate (induction time) for a given level of supercooling below the dissociation temperature has not been quantified, but the probability of hydrate formation definitely increases as you move toward the supercooled temperature.

The time it takes for hydrates to form when operating between the dissociation curve and the supercooled curve decreases as the temperature approaches a supercooled state.

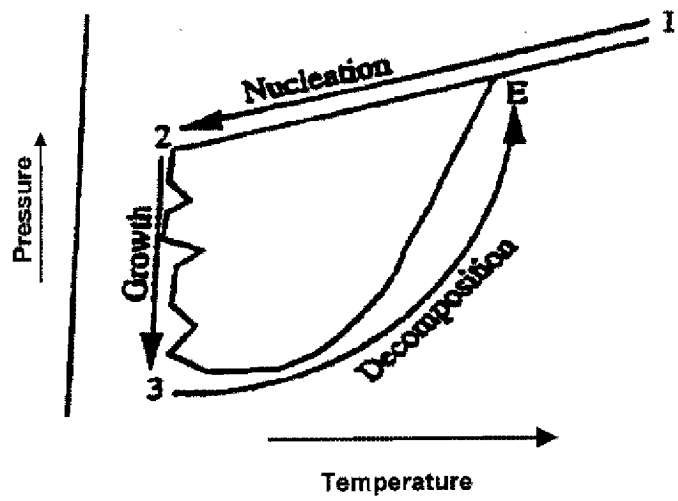


Figure 1-19 Schematic of constant-volume temperature ramping experiment.

1.4.3 Pre-planning

See also *Well Control Procedures, 2.3, Circulating to Kill*

Gas hydrate control and mitigation plans should be in place prior to undertaking any deepwater drilling operation.

Minimize hydrate formation risk with inhibited mud system, appropriate well control procedures, and necessary contingency plans

In order to minimize the risk of hydrate formation, a combination of a sufficiently inhibited mud system and appropriate well control procedures should be incorporated, as well as plans to minimize the reaction time to deal with hydrates if they do materialize. An analysis of hydrate formation potential and the associated risk should be made.

"Worst case" conditions used for design:
- **Static temperature gradients**
- **Realistic mud weight schedules**
- **Conservative gas compositions**

Typically, "worst case" conditions are identified and used for design. For example, static temperature gradients should be used to determine the amount of inhibition required in the mud system since extended shut-in periods are very possible when circulating out a gas kick due to lost circulation, drill string plugging, annular packoff or severe weather conditions.

Realistic pressure (mud weight) requirements and conservative gas compositions, if not accurately known, should be used when determining the amount of temperature suppression required.

Contingency plans should be developed addressing well control procedures, extended shut-in periods and hydrate remediation, as follows:

- **Well control procedures** – either the driller's method or the wait & weight methods are acceptable (see Well Control Procedures, 2.3, Circulating to Kill).

- **Extended shut-in periods** - obviously these times are unplanned and should be kept to a minimum. Static temperature gradients should be used to determine the amount of inhibition required in the mud system. If the

level of inhibition still only suppresses the hydrate formation temperature into the supercooling or metastability region on the phase diagram, plans should be in place to displace the choke and kill line and BOP cavity with a glycol inhibitor at some point after a shut-in is experienced, depending on the anticipated shut-in time and how far below the dissociation point the system is designed. Enough glycol based inhibition product should be available to displace the calculated volume with at least a 50% safety factor.

- **Hydrate remediation** - there have been many successful methods used to clear hydrate plugs once they have formed, the key is to minimize the reaction time if they do form. Some degree of super-heating (or depressurization) above the phase curve is usually required to initiate timely decomposition of hydrates. Dissociation of hydrates can develop dangerously high pressures due to the "stored energy" of the gas trapped inside. One cubic foot of hydrate can hold 170 standard cubic feet of gas. Always ensure there is an escape path for the melting hydrate gas to vent. Closed containers like conventional core barrels should always be suspect. Adding upstream pressure only adds too and complicates the problem.

1.4.4 Methanol Injection

Methanol injection works very well on the surface and in downhole production systems, but to date, has not been used downhole during drilling operations due to its toxicity and volatility.

Hydrates in BOP cavity and C&K lines

For hydrates forming in BOP cavity and choke and kill lines with the well shut-in, circulating at the highest possible rate with hot fluid or mud across BOPs, down a second drillstring, or through coiled tubing run beside the drill pipe has worked to dissociate the plug. The internal diameter of the second string of pipe run should be maximized to reduce the time and pressure required to displace the heated fluid to the area needing heat. However, below 4,000 ft water depth this process is extremely marginal due to heat loss and ambient temperature cooling effect.

Perforating drill pipe above hydrate plug not recommended

Never perforate the drill string above the hydrate plug in an attempt to establish circulation as the potential for hydrate formation inside the drill pipe is great, and ultimately could cause loss of access to the wellbore below the plug that may be necessary for further remediation.

1.4.5 Inhibition

See also *Well Planning, 1.3.6.1, Hydrate Prevention*

There are two common processes incorporated into the drilling mud system for inhibition:

1.4.5.1 Thermodynamic inhibitors

Thermodynamic inhibitors suppress the temperature required for hydrate stability

Thermodynamic inhibitors lower the activity level of the aqueous phase, thereby suppressing the temperature required for hydrate stability at any given pressure. Primarily, these are electrolytes and polymers listed in Table 1-10 on the following page.

1.4.5.2 Kinetic inhibitors

Kinetic inhibitors slow the rate of hydrate formation

Kinetic inhibitors (or crystal modifiers) alter the nucleation and growth of hydrates by using a low concentration of mostly polymeric and surfactant based chemicals without disrupting the thermodynamic equilibrium of the hydrates. These type inhibitors delay the appearance of the critical nuclei, slow the rate of hydrate formation and prevent the agglomeration process. Much is still to be learned about this process.

Combinations of both processes will most likely be required as conditions become increasingly severe.

Common Thermodynamic Hydrate Inhibitors	
SALTS	**ALCOHOL/DIOLS**
NaCl	Methanol
KCl	Ethanol
$CaCl_2$	Glycerol
Na-Formate	Ethylene glycol
K-Formate	Propylene glycol
NaBr	Polyalkylene glycol
$CaBr_2$	
$ZnBr_2$	

Table 1- 10 Common thermodynamic hydrate inhibitors

Salt/polymer inhibition systems

Salt/polymer inhibition systems are most commonly used during deepwater drilling in the Gulf of Mexico, North Sea & offshore Brazil. Systems comprised of 20-26% by weight sodium chloride (NaCl) with required polymers have been safely used in water depths >7500 ft in the presence of gas kicks.

Among the electrolytes or salts, NaCl is the best thermodynamic inhibitor. Figure 1-20 below illustrates the degree of hydrate temperature suppression as a function of NaCl concentration by weight percent.

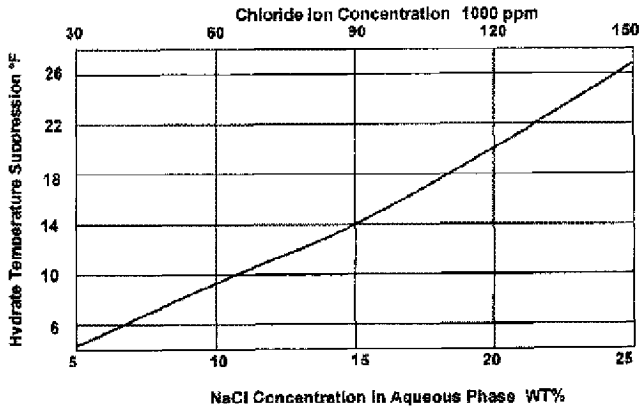
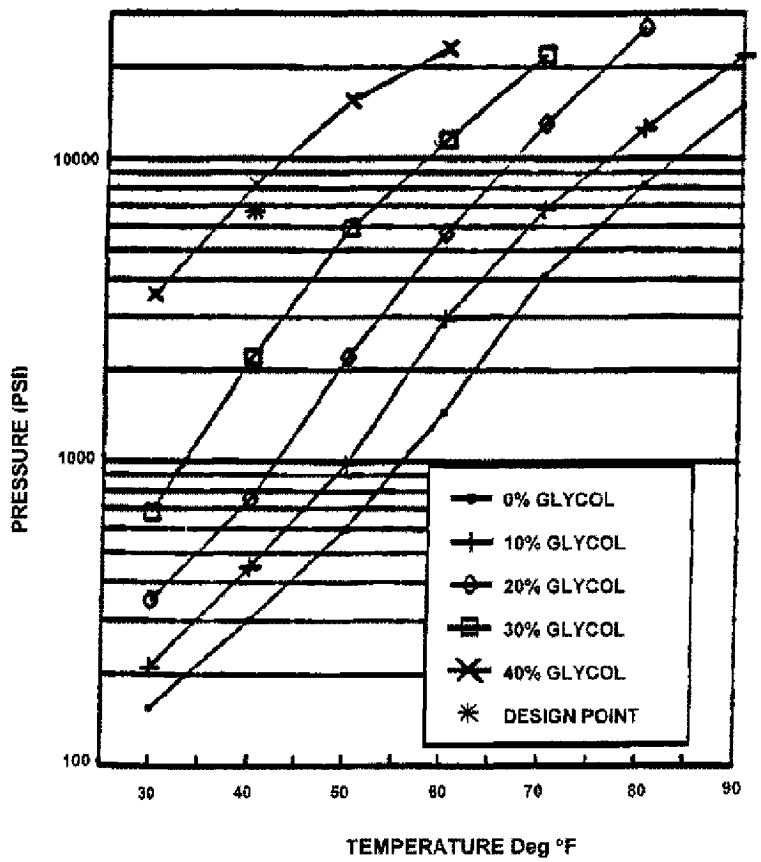


Figure 1-20 Degree of hydrate temperature suppression as a function of NaCl concentration by weight percent.

Glycols are also effective inhibitors as can be seen in Figure 1-21 below, but are less effective than salts on weight basis and experience severe viscosity increases at cooler temperatures. They are excellent in combination with salt systems at lower concentrations. At 90°F it is virtually impossible to form stable hydrates under normal well control pressure ranges.

Glycols may experience severe viscosity increases at cooler temperatures

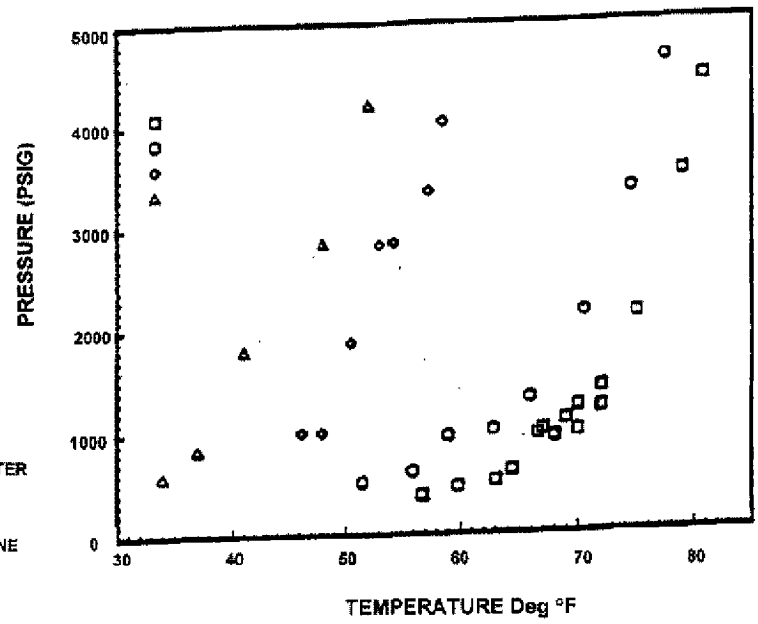


Shaughnessy, J., R. Carpenter, R. Coleman, and C. Jackson. "Successful Flow Testing of a Gas Reservoir in 3,500 Ft of Water." JPT, July 1992.

Figure 1-21 Inhibition of hydrate formation caused by glycol.

Oil-based and synthetic-based muds also require inhibition

Oil based and synthetic oil based mud systems do allow hydrates to form since there is a water phase as can be seen in Figure 1-22 below. The salinity of this water phase must be adjusted for the required inhibition level as in water based mud systems.



LEGEND
- □ WATER
- ○ OIL BASE MUD + WATER
- ◇ 19.22% $CaCl_2$ BRINE
- △ OIL BASE MUD + BRINE

Grigg, R. and G. Lynes. "Oil-Based Drilling Mud as a Gas Hydrates Inhibitor." SPE 19560, 1992.

Figure 1-22 Comparison of gas hydrate formation points for four mud systems

NaCl saturation

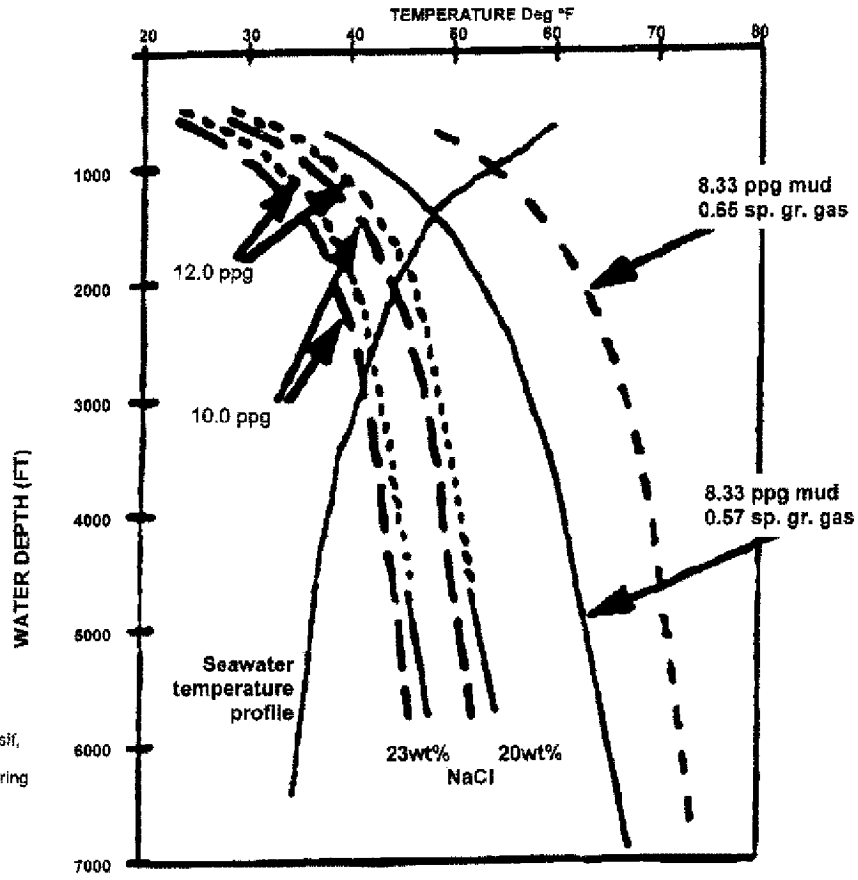
Table 1-11 below shows the result of increasing the weight percentage of NaCl to saturation at approximately 26% as a function of specific gravity, mud weight and parts per million (ppm). It must be noted that observed fracture gradients can not always handle the required mud weights for necessary inhibition.

Densities of Sodium Chloride (NaCl) Solutions at 68°F						
SPECIFIC GRAVITY	% NACL BY WEIGHT OF SOLUTION	WEIGHT OF SOLUTION		PARTS PER MILLION	MILLIGRAMS PER LITER	
		PER GALLONS	PER CU FT			
0.9982	0	8.33	62.32	0	0	
1.0	0	8.34	62.40	0	0	60°F
1.0018	0.5	8.36	62.54	5,000	5020	
1.0053	1.0	8.39	62.76	10,000	10,050	
1.0125	2.0	8.45	63.21	20,000	20,250	
1.0197	3.0	8.51	63.66	30,000	30,700	
1.0268	4.0	8.57	64.10	40,000	41,100	
1.0341	5.0	8.63	64.55	50,000	52,000	
1.0413	6.0	8.69	65.01	60,000	62,500	
1.0486	7.0	8.75	65.46	70,000	73,000	
1.0559	8.0	8.81	65.92	80,000	84,500	
1.0633	9.0	8.87	66.37	90,000	95,000	
1.0707	10.0	8.93	66.84	100,000	107,100	
	11.0			110,000	118,500	
1.0857	12.0	9.06	67.78	120,000	130,300	
	13.0			130,000	142,000	
1.1009	14.0	9.19	68.73	140,000	154,100	
	15.0			150,000	166,500	
1.1162	16.0	9.31	69.68	160,000	178,600	
	17.0			170,000	191,000	
1.1319	18.0	9.45	70.66	180,000	203,700	
	19.0			190,000	216,500	
1.1478	20.0	9.58	71.65	200,000	229,600	
	21.0			210,000	243,000	
1.1640	22.0	9.71	72.67	220,000	256,100	
	23.0			230,000	270,000	
1.1804	24.0	9.85	73.69	240,000	279,500	
	25.0			250,000	283,300	
1.1972	26.0	9.99	74.74	260,000	311,300	
Note: It is quite common for many laboratories analyzing water samples to report milligrams of salt per liter as parts per million.						

Table 1- 11 Densities of sodium chloride (NaCl) solutions at 68°F.

599938650

Figure 1-23 illustrates that below approximately 3000 ft water depth, inhibition with salt alone can not guarantee a hydrate free environment.



Ebeltoft, H., M. Yousif, and E. Soergaard. "Hydrate Control during Deepwater Drilling: Overview and New Drilling Fluids Formulations." SPE 38567. 1997.

Figure 1-23 Effect of gas gravity, mud weight and salt content on hydrate stability.

1.4.6 Potential Problems

The two types of hydrate formation problems are as follows:

1. Shallow gas percolating from an external unsealed annulus between the low pressure and high pressure wellhead housings that makes its way up inside the BOP stack connector which prevents the hydraulic disconnect from functioning.
2. Formation inside the wellbore or BOP equipment hindering control of BOP functions and access to the wellbore.

1.4.6.1 Shallow gas invades BOP stack connector

Hydraulic disconnect cannot function

Occurrences of the first type problem have been fairly common, but can be eliminated (or at least the potential for occurrence greatly reduced) by inserting a "hydrate seal" in the bottom of the high pressure wellhead/BOP connector, or installing some type of diversion apparatus, like a mud mat, that will cause any gas seepage to bypass or be diverted away from this area as illustrated in Figures 24 and 25 below.

Connector Hydrate Seals

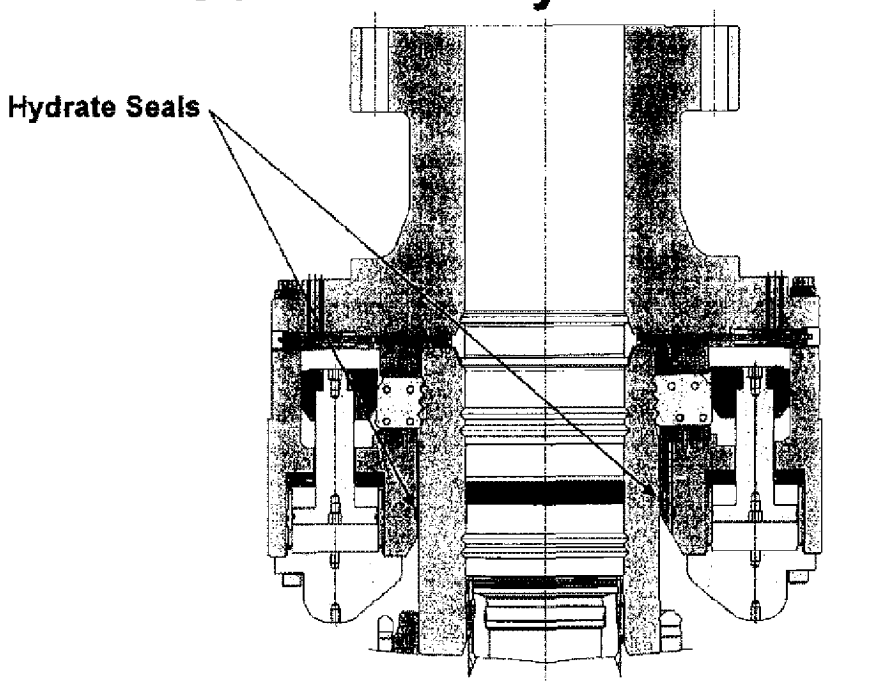


Figure 1-24 Elastomer hydrate seal.

Mudmat Hydrate Seals

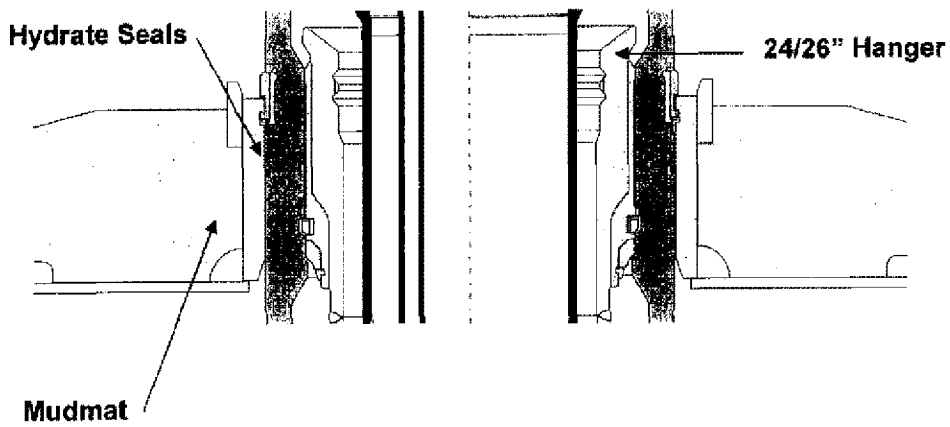


Figure 1-25 Mud mat hydrate seal.

This type of hydrates, formed by percolating gas, has been visually documented numerous times and have caused wells to be permanently abandoned and sacrificed that otherwise would have been temporarily abandoned for a future completion. Typically, the rig and riser can be "winched" around to cause the hydrate to break or loosen up. Circulation of heated fluids down the drillstring both on the inside and the outside of the connector has also worked successfully.

1.4.6.2 Hydrate formation inside wellbore or BOP equipment

See also *Well Control Procedures, 2.5, BOP Cleanout (Trapped Gas)*

BOP functions hindered

The second problem, where hydrates form inside the wellbore or BOP equipment, is much more serious from a well control standpoint and can affect an operation in many different ways.

Hydrates usually do not form during routine drilling and/or circulating

Circulating out gas through C&K lines creates favorable conditions for hydrate formation

Hydrates typically do not form during routine drilling and/or circulating operations since the combination of required properties do not exist. Hydrates usually occur when a gas influx is taken into the wellbore and is being circulated out through the choke and/or kill line. Hydrates form from increased velocity and expansion cooling in the lines, or during an extended shut-in period where the gas bubble reaches the mudline, rapidly cools, and forms hydrates in the wellbore and/or choke and kill lines.

Many different scenarios involving this type of hydrate formation have been observed and documented, including the following:

- Hydrate plug in the choke and/or kill line causing inability to continue circulating out kick.
- Hydrate plug in the BOP cavity or just below stack resulting in loss of wellbore circulation and pressure monitoring.
- Hydrate plug in the drill string-x-riser (or BOP or casing) annulus causing stuck pipe.
- Hydrate plug in the drill string BOP annulus opposite a preventer hampering shut-in capability.
- Hydrate plug behind a closed ram not allowing the ram to be opened back up.

Remedial actions for all of these situations should be evaluated thoroughly prior to undertaking any deepwater drilling activity.

Improper BOP functions may be hydrate related

Any non-routine occurrence with any BOP function or subsea wellhead equipment should be suspect for hydrate formation, especially during an extended shut-in period.

These incidents may include the following:

- improper functioning or hydraulic operating fluid requirements of valves, rams or connectors
- depth measurement discrepancy when setting casing hanger seal assemblies even if a positive test has been experienced
- problems running and/or retrieving the seat protector

Hydrates extract free water from drilling mud

Another problem that has been observed is actually caused by the formation of hydrates. Hydrates will extract free water from the drilling mud, causing it to dehydrate and settle out similar to a barite plug.

1.4.7 Defense

The following guidelines should be used as minimum requirements when planning deepwater drilling operations:

Well Control Procedures

Well control procedures and team training should be in place, agreed upon and communicated to all involved personnel addressing the following issues:

- shut-in procedures
- kill method desired under specific scenarios
- minimum circulating rates required
- coordination to minimize the number and duration of shut downs

Gas Influx

As much as possible, avoid any gas influx into the wellbore. Minimize any that do occur through proper mud weights, mud rheology and trip procedures.

Inhibitive Mud System

A well-engineered low fluid loss mud system should always be designed incorporating the proper type and amount of inhibition for the required temperature suppression.

Lost Circulation

Avoid lost circulation situations. Consider having LCM pills prepared and ready to be pumped for emergency situations in contingency plans.

Inhibitive Spotting Fluid

Have inhibited spotting fluid available to displace the choke and kill lines and BOP cavity during extended shut downs addressed in contingency plans.

Contingency Plans

Contingency plans should be in place for remedial action if hydrates form that include locating and coordination of fluid heating and pumping equipment, coil tubing, heat generation chemicals, etc.

Personnel

Experience invaluable

Personnel experienced with hydrate formation conditions and early recognition of their formation potential during well control operations are essential for avoidance.

1.4.8 Heat Generation Systems

The following list of equipment is readily available and has been used successfully in the past to dissociate hydrate plugs:

- Steam boiler with shell and tube heat exchanger.
- Immersion heaters for mud pits.
- Hot oil barges with self-contained heating and pumping equipment.
- Throttling the choke sub to deliver hydraulic horsepower energy (hence heat) to the BOP area.

Drawbacks to hot oil barges:
- **Operate with diesel or water only, not mud**
- **Cannot operate in rough seas**
- **Require complex plumbing**

Hot oil barges have many drawbacks that minimize their usefulness. They only operate with diesel or water, not mud, and therefore create a need to evaluate the loss of hydrostatic pressure if utilized. They cannot operate in rough seas, and therefore are an unreliable source. They typically require a lot of arduous plumbing that minimizes the available horsepower and residual heat, that already is limited, as well as introducing new risks.

For an understanding of heat generation and capacity: 10.0 ppg mud will generate four times as much heat as water.

Computer thermal modeling can help determine the necessary and optimum circulation rates, pressures, nozzles, external heating (if needed), and whether fluid

should be recirculated or if suction should be taken with warm seawater at the surface.

1.4.9 Remediation Guidelines for Hydrate Occurrence

The following steps could be implemented in the event of hydrate formation:

Step	Action
1	Plug off and isolate any open hole interval.
2	Locate and move steam generator and heat exchanger to dock with minimum capacity of 400 gpm and 500 psi working pressure.
3	Locate and move a minimum of 10 immersion heaters to dock and assess the need for more -110°F desired mud temperature.
4	Locate and move a string of 4" drill pipe (amount equal to water depth plus 500') with the associated handling tools to the dock.
5	Have a dual surface diverter element manufactured to accommodate the two string sizes being utilized simultaneously if necessary.
6	Run a neutron decay unfocused density log through drill pipe to identify and accurately locate the hydrate plugs.

1.5 Drill Stem Testing

1.5.1 Summary

The objective of drill stem testing is to safely perforate, flow, kill and abandon a horizon from a floating rig. This is currently being done in water depths of 5,000 ft and deeper.

High rate completions necessary to make deepwater wells profitable

High rate completions are required to make ultra deepwater wells profitable. The rig must handle the flow with equipment squeezed into the available space. All surface equipment and the test string down to the seafloor are subjected to dynamic loads caused by the rig's motion.

Key differences between floating and fixed rig completions

- **Inability to move tubing below seafloor**
- **Need to compensate for motion above seafloor**

A limited number of companies provide equipment to test wells from floating rigs. While much of the equipment is very similar, the main point that separates floating rig tests from those done on fixed platforms or jackups is the inability to move the tubing below the seafloor and the need to compensate for motion above the seafloor.

Space out of equipment in subsea BOP stack is critical

The space out of equipment in the subsea BOP stack is critical. The space out between the seafloor and the reservoir is critical to ensure that the equipment lands correctly in the stack and thermal changes on the string are compensated.

Dynamically positioned rigs run similar testing assemblies, but must be designed for a potential emergency disconnect. The design requires quicker reaction times and more contingency planning.

1.5.2 Considerations in Floating Testing Planning

The discussion below includes basic information and points that should be considered in floating testing planning.

1.5.2.1 Unique test string equipment

The following briefly describes the tools that make up the testing string, starting from the bottom.

Annulus Activated Testing Valve

Annulus activated testing valve can provide fast shut-in point close to perforations

The annulus activated testing valve is usually a full opening ball valve that is opened by applying annulus pressure down a choke or kill line beneath a closed ram. The valve fails closed when annulus pressure is lost. When run just above the bottom packer, it provides a shut-in point close to the perforations that can be closed quickly.

Circulating Valve

Circulating valve establishes underbalance prior to perforating or when opening well to flow, or is used for circulating kill mud after testing

The circulating valve is usually run just above the annulus activated testing valve. It is functioned open by cycling pressure either on the tubing side or annulus (depending on the supplier).

Note: Annulus cycling pressure must be below the testing valve activating pressure.

The circulating valve is used to establish an underbalance prior to perforating or when opening the well to flow or to circulate kill fluids into the string at the end of the test.

Drill Collars

Drill collars provide weight to resist forces on string

Drill collars provide the necessary weight to resist hydraulic and thermal forces on the string. The thread can be modified to provide an "O" ring for improved reliability.

Slip Joints

Slip joints provide necessary travel or adjustments for the test string as it is warmed up by the flowing production. The space out between the wellhead and the subsea tools requires a slip joint as well.

Tubing

Premium connection

A premium tubing connection is recommended.

Injection Sub

Hydrate inhibitor injection

The injection sub is used to inject hydrate inhibiting chemicals. It is spaced out below the point where hydrates will form due to cooling.

Fluted Hanger

Fluted hanger ensures test tree is properly spaced out

The fluted hanger lands in the subsea wellhead. The string below it does not move. When it is in place the test tree is spaced out properly in the subsea BOP.

Slick Joint

The subsea BOP rams are closed on the slick joint. Annulus pressure is applied below the ram closed on the slick joint. Ideally, the test tree ball valves are spaced out just above the slick joint.

Slick joint must be ported for injecting hydrate inhibitors

When hydrate inhibiting chemicals are injected into the test string downhole, the slick joint must be ported. The rams could not close on a chemical injection line, so the line is tied into the top of the slick joint and on the bottom below the close in point. Since the port by-passes the rams, check valves are installed to isolate wellbore pressure in the event of an injection line failure.

Test Tree

The test tree is a full opening ball valve designed to fail close when operating pressure is lost. The tree can be unlatched and the ball valve left closed to secure the well if a disconnect of the drilling riser is necessary.

Tree can be unlatched and the ball valve left closed to secure the well if a riser disconnect is necessary

When disconnected a secondary flapper seal will also provide wellbore isolation. The ball valve closing mechanism can be pressure boosted to cut wireline if it is in the well when a disconnect was necessary. The trees usually have a port for chemical injection into the flow stream.

Retainer Valve

Retainer valve traps test fluids in the tubing string in the event of emergency disconnect

The retainer valve is a fail close valve that is run just above the test tree. Its function is to trap test fluids in the tubing string in the event of an emergency disconnect. It ensures no high pressure fluids are released to the riser.

Tubing to Surface

Premium connection

It is more critical that a premium connection be run in this tubing because it is subject to cyclical loads caused by rig motion and a failure releases hydrocarbon above the BOPs.

Lubricator Valve

The lubricator valve is run 3 - 4 joints below the rig floor. It stays in the last position, either open or closed, functioned. It allows the upper portion of the tubing string to be used as a lubricator for running wireline tools.

Surface Control Head

The surface control head provides flow control and a shut-in point on the rig floor.

1.5.2.2 Disconnect and shut-in speed

Trees available with 15 second disconnect time

Disconnect and shut-in speeds are critical for tests from DP rigs. Trees are available that will disconnect in 15 seconds. That must be done quickly in order to provide enough time for the rig's disconnect sequence, which is generally 30 seconds.

As noted above, the watch circle must be reduced by this time. Therefore, the shorter the time the better.

Shear test string in the event the release does not function

Authorization to shear the test string in the event the release does not function should be clear to the crew. If an emergency disconnect is required, alternative release methods must be instantaneous. Failure to release the riser threatens the entire system.

Modifications to Watch Circle

See also *Well Control Procedures, 2.11.3, Watch Circle*

The watch circle for a dynamically positioned rig should be reduced by the distance the rig will move while shutting-in and disconnecting the test tree in the event of a drive or drift off.

For example, if for a given sea state the rig will move 50 ft during the 15 seconds required to close and unlatch the tree, the watch circle alarm levels should be moved in 50 ft. That provides the crew time to secure the well and release the riser prior to reaching a limit on the riser offset.

BOP Shear Requirements

The test string should be spaced out in such a way that the shear rams can cut what ever is opposite them and seal off the hole. On a DP rig the speed required for disconnecting the riser in an emergency disconnect requires the shear rams be the back up release to the test tree's connector.

The test tree will likely have a mechanical release that requires rotation. Rotation would usually be acceptable for a planned disconnect, but could not be done fast enough in an emergency.

Number of Shut-in Points

Ported slick joint required for injection below mud line

Between the downhole annulus activated testing valve, subsea test tree and retainer valve there are usually redundant methods to secure the well. The greater redundancy improves the ability to secure the well, but increases complexity.

Port by-passes the BOP, install check valves above and below slick joint

1.5.3 Hydrate Inhibition

See also *Well Planning, 1.4, Hydrates*

Well Planning, 1.3.6.1, Drilling Fluids, Hydrates Prevention

Hydrates are an ice-like mixture of natural gas and water that can form at temperature above the freezing point of water. Hydrates can plug up tubing and prohibit any circulation. Additions of chemicals, primarily glycol or methanol, can reduce the temperature at which point hydrates will form. If an aqueous mixture would form a hydrate at 39° F and 1,000 psi, the addition of chemicals can increase that formation temperature to 80° or 90° F.

Methanol is a better inhibitor than glycol but is much more volatile

Methanol is a better inhibitor than glycol and less viscous (more easily pumped), but it is much more volatile (flash point of +/- 60° F, meaning if methanol vapor is at that temperature or higher and exposed to a spark, it will burn).

During testing, a chemical injection sub is installed in the test string at a depth where temperature simulations indicate the flow stream will not have cooled to hydrate formation temperature. The chemicals are injected through a small line strapped to the test tubing.

To inject below the mud line a ported slick joint is required because the BOP stack rams could not seal on the injection

line. The port is a small diameter hole drilled in the pipe wall. The rams close on the OD of this slick joint to allow applying annulus pressure to downhole tools. Thus, the port by-passes the BOP.

Place injection point as close to mud line as possible

Check valves should be installed above and below the slick joint for that reason. Also, when pulling the test string out of the hole at the end of the test, if the well were to flow the chemical injection line may not allow the rams to seal. Therefore, the injection point should be as close to the mud line as possible.

1.5.4 Flaring vs. Barging Produced Oil

The MMS regulates the length of time a well may be flared due to concerns over pollution and lost reserves. Achieving an efficient burn during start up and at high flow rates is also a concern.

Using barge or tanker for oil transport presents mooring problems

If oil can not be flared efficiently it will be necessary to gather the oil in a barge or tanker to transport to shore. This presents mooring problems in shallow water due to interference of anchor lines. If the weather window allows, the barge could be held in position with a tug.

Mooring two DP vessels in close proximity may create hazard

There is another disconnect problem in ultra deepwater when two dynamically positioned vessels would be moored in close proximity. An upset to either positioning system creates a major hazard.

Surface Equipment Requirements

- **All skids welded to deck**
- **All interconnecting piping tested to design or maximum potential shut-in pressure**

The equipment should be designed for the potential motions that the rig could experience in the potential weather window. All skids should be welded to the deck. All interconnecting piping should be pressure tested to either design pressure or maximum potential shut-in pressure.

Surface Heat Requirements

An open flame is usually necessary to generate steam or to heat a fluid that is circulated to the heat exchanger. Precautions should be taken to locate the heater away from the rig floor and potential sources of hydrocarbons.

Length of Flow Period

MMS approval required for extended flaring

This is set by the reservoir evaluation objectives of the test. MMS approval is required for any extended flaring period.

Length of Shut-in Period

This is set by the length of flow period and the extent of reservoir evaluation required.

Wireline Work Limitations

Wireline may be affected by hydrate formation

If hydrates are a concern, the contingency planning required to melt a hydrate plug may limit the use of wireline while the tubing is full of gas. For example, it may be difficult to run a coil tubing string down to a hydrate plug if wireline is frozen in the tubing.

1.5.5 Recommended Precautions

Detailed procedure with contingency planning for all potential component failures

A detailed procedure with contingency planning for all potential component failures is recommended. Rig supervisors should have full control on the testing operations. Gas testing equipment prior to the test is also recommended.

Pressure Testing of Tubing

The tubing connections inside the marine riser are subject to cyclical rig motion. There is no containment for a failure or leak of these connections. The connections can be pressure tested while running after make up. In shallow water it may be possible to test the entire string against the test tree.

Diverter Element Modifications

A special built diverter element should be considered that is modified for the subsea test tree control lines and a possible chemical injection line. The modified insert reduce the potential for releasing gas to the rig floor in the event of a tubing leak above the seafloor.

Weather Considerations

Several factors must be considered when addressing weather limitations, including but not limited to the following:

- the reduction of the watch circle for DP rigs
- the vessel motion and limits on surface equipment handling
- the ability to offload oil to a barge
- the ability to maintain an efficient flare

1.6 Deepwater Regulatory Guidelines

The following document is categorized as follows:

1. A summary of the regulatory overview pertaining to deepwater operations
2. Special considerations and concerns for these same operations
3. Permit process overview

1.6.1 Summary

Recent discoveries in the deepwater shelf and slope regions of the Gulf of Mexico, deepwater royalty relief, and new technology are some of the major contributors to making the deepwaters of the Outer Continental Shelf (OCS) Gulf of Mexico the scene of a relatively intense search for oil and gas fields.

Issues include:
- **timing, scale of operations**
- **environmental impacts**
- **tankering**
- **extended well testing**

The recent surge in deepwater leasing and activities has generated concern over many issues related to deepwater operations. Issues include timing and scale of deepwater operations, potential environmental impacts associated with the new technologies for drilling in deepwater areas, oil tankering from deepwater areas, and extended well testing. Some of the key issues addressing safety, technical, and environmental reviews are as follows:

- new and unusual technologies
- oil-spill contingency planning
- sour-gas production
- monitoring casing pressure
- chemosynthetic communities
- live bottom areas
- pinnacle and other hard-bottom habitats
- air quality
- water quality
- endangered and threatened species
- pipeline tows and landfalls
- lease abandonment and decommissioning operations

1.6.2 Differences between Deepwater and Shallow Water Operations

Deepwater operations differ from those conducted in the shallower water. Deepwater operations may involve a number of conditions, including:

- significantly more remote location
- subject to different environmental conditions
- more sophisticated technologically
- higher production rates
- subject to different economic determinants

Existing regulations may not be directly applicable to deepwater

Because operations and equipment used in deepwater are different from those used in shallower waters, the existing regulations, originally written for conventional, shallow water operations cannot be directly applied to proposed deepwater operations in many cases.

Deepwater operations present many challenges including identifying risk and incorporating that risk into the permitting decisions. Another challenge will be evaluating and mitigating potential adverse environmental impacts.

The agencies and industry are working diligently to keep pace with evolving deepwater issues and technical expertise, and are continuously developing the regulatory framework required to manage risk effectively. In 1992, the Minerals Management Service (MMS) formed in internal Deepwater Task Force to address technical issue and regulatory concerns relating to deepwater (greater than 1000 ft or 305 m) operations and projects utilizing subsea technology.

Operators required to submit a Deepwater Operations Plan (DWOP)

Based upon the Deepwater Task Force's recommendation, a Notice to Lessees (NTL 96-4N) was developed which requires operators to submit a Deepwater Operations Plan (DWOP) for all operations in deepwater and all projects using subsea technology.

The DWOP was established to address regulatory issues and concerns that did not exist in the current MMS regulatory framework and to initiate an early dialogue

between MMS and industry before major capital expenditures on deepwater and subsea projects are committed.

Deepstar: cooperative workgroup for deepwater regulatory and technology issues

Deepstar, an industry-wide cooperative workgroup focuses on deepwater regulatory issues and critical technology development issues, and works closely with the MMS Deepwater Task Force to develop the guidelines attached to the referenced NTL.

The increase in deepwater activity is due in large to the enactment of the Deepwater Royalty Relief Act in 1995. Other factors contributing to the incease in OCS activities related to technological advancements occurring in the industry, including 3D and 4D seismic surveying and horizontal drilling.

The recent surge in deepwater leasing and activities has generated concern over many issues related to deepwater operations, including the following:

- timing and scale of deepwater operations
- potential environmental impacts associated with the new technologies for drilling and production in deepwater areas
- tankering from deepwater areas
- expansion of the pipeline system
- wetlands impacts due to increasing number of landfalls
- gas flaring during extended well testing
- noise associated with 3D seismic surveying
- compatibility of current infrastructure with anticipated larger support vessels
- possibile deepening of navigation channels and ports to accommodate these larger vessels
- increased demand for fresh water
- increased economic and industrial activity in the coastal zone
- additional service vessel and helicopter traffic
- increased traffic on existing roadway
- in-migration of workers

Environmental and technical unknowns in the deepwater area create the need for revised regulations, new policies and guidance. Emphasis on deepwater development and the

associated innovative technology for drilling, as well as the need to address engineering and safety will present challenges to the industry and the regulating agencies.

Deepwater development is expected to increase the number of Plans of Exploration and Development Operations Coordination Documents. The more complex and larger proposals for deepwater operations will require more extensive environmental reviews. Impacts to endangered, threatened, and/or protected species may become an issue as development moves into deeper waters.

MMS and industry have identified numerous regulations requiring departure or alternative compliance approval

Currently, 27 existing regulations have been identified by the MMS and industry as requiring a departure or alternative compliance approval to permit development operations to proceed. A departure can be granted when necessary if the operator can demonstrate that an acceptable level of safety exists. Details of these departures and/or alternative compliance are listed in Section 1.6.3.

Structure removal and site clearance for deepwater structures may present additional environmental concerns and new technological and regulatory challenges. Because of higher structure removal costs, industry is expected to request approvals for mid-water abandonments, leaving lower sections of decommissioned structures that have little or no environmental benefits as artificial reefs. Department of Defense issues, disposal at sea, and liability issues will need to be addressed.

Over time, the permitting issues will most likely become even more increasingly complex. New issues, new laws and regulations, and new and expanding operations from deepwater exploration, discovery, and production will intensify the demands on the agencies governing such operations.

1.6.3 Concerns and Special Considerations

As previously stated, the current regulations in place are not necessarily adaptable to the deepwater operations in the OCS Gulf of Mexico.

Initial permitting stages

During the initial permitting stages, the following areas are given consideration by MMS:

1.6.3.1 High resolution geophysical survey reports

Regulations in place presently require conducting a high resolution geophysical survey across the areas of proposed surface disturbance. The purpose of this survey is to determine the presence of an potential shallow drilling hazards, as well as identify areas of cultural significance.

Certain types of data acquisition are ineffective in deeper water depths

In certain cases, MMS will grant departures from conducting certain types of data acquisition, such as the magnetometer and/or side scan sonar due to the ineffectiveness in deeper water depths.

1.6.3.2 3-D seismic surveys

Use of 3-D seismic for shallow hazard interpretation

In lieu of conducting the aforementioned high resolution geophysical surveys, MMS will review and possibly consider the use of 3-D seismic data for interpretation of shallow drilling hazards and restraints. This can be accomplished by contacting MMS prior to the submittal of permit filings, and providing a bathmetry map and a seafloor rendering map with applicable 3-D seismic data.

Subject to MMS pre-approval process, a detailed narrative interpretation of this data must be supplied for each surface disturbance (i.e., well locations, anchoring locations) being proposed.

1.6.3.3 Ordnance areas

Military ordnance areas have been established throughout the OCS Gulf of Mexico (normally in deeper waters) which are utilized as a disposal site. Special consideration should be given when proposing surface disturbances in these areas due to the sensitive nature of items disposed.

1.6.3.4 Applications for permit to drill

Subsequent to obtaining approval to drill a well under an approved Plan of Exploration or Development Operations Coordination Document, an operator must submit a detailed drilling program for approval to the MMS District Office.

Variance from 0.5 ppg margin requirement

A special consideration which may be given for such applications in deepwater is a variance from the normal safe margin of 0.5 ppg between the last shoe test and the maximum mud weight during each applicable interval. In certain cases, (i.e., water depths greater than 3000 ft) MMS may consider variances of up to 0.2 ppg for the conductor casing interval and 0.3 ppg for the surface casing interval.

1.6.3.5 Relief wells

See also Emergency Response, 4.4, Rig Positioning and Surveying for Relief Wells

Deepwater rig availability is limited

A concern has recently been voiced by MMS about the possibilities of rig availability for the potential drilling of a relief well. In deepwater, rig availability is not as abundant as on the shelf. MMS is currently proposing to issue rulemaking which will establish the operator's responsibility for ensuring MMS on the accessibility and availability of such drilling units.

1.6.3.6 Financial responsibility

Bonding requirements

MMS is proposing new rulemaking which will impose additional bonding requirements for those exploratory and development lease activities related to deepwater operations.

Additionally, MMS has recently signed off on final rulemaking increasing the financial responsibility on potential oil spills from a set limit of $35,000,000 to an increased amount dependent upon worst case discharge with a range from $35,000,000 to $150,000,000.

1.6.3.7 Extended well tests

See also Well Planning, 1.5, Drill Stem Testing

In many cases, an operator may need to conduct an extended well test to delineate the reservoir being explored, in order to determine the potential for further activity. Again, the MMS reviews these types of requests on a case-by-case basis.

Capture rather than burn liquid hydrocarbons

An operator is required to submit a request to MMS for any flaring of gas beyond the initial 48 hour period, and for the burning or capturing of any liquid hydrocarbons. Such request must address the estimated volumes, maximum flow rates, anticipated gravity and sulphur content; as well as how the liquids will be handled. MMS strongly encourages the capturing of liquid hydrocarbons rather than burning in support of conservation and potential for spills.

1.6.3.8 Deepwater Operations Plans

Effective August 19, 1996, Minerals Management Service (MMS) issued a Notice to Lessees and Operators (NTL96-4N) pertaining to deepwater/subsea development projects, which has recently been superseded by NTL 98-8N, effective June 1, 1998.

This NTL references the requirements for submittal of Deepwater Operations Plans (DWOPs) for all deepwater development projects in water depths greater than 1,000 ft, and all projects involving subsea technology.

The DWOP is designed to address industry and MMS concerns by allowing an operator to know, well in advance of significant spending, that their proposed methods of

dealing with situations not specifically addressed in the regulations are acceptable to MMS.

DWOP addresses specific deepwatersubsea equipment issues

The DWOP will provide MMS with information specific to deepwater/subsea equipment issues to demonstrate that a deepwater project is being developed in an acceptable manner as mandated in the OCS Lands Acts amended and Title 30 CFR 250. MMS will review deepwater development activities from a total system perspective, emphasizing the operational safety, environmental protection, and conservation of natural resources.

The MMS DWOP is submitted in three phases to the MMS Regional Gulf of Mexico Office in New Orleans, LA, Attention: Chief, Technical Assessment and Operations Support Section (MS 5221).

Three copies of the plan are required; unless the project involves more than one MMS District, which then will require one additional copy for each District. Upon MMS determining that each part of the DWOP contains all the necessary information, each phase will be approved within the following time schedule (calendar days):

1. Conceptual Part - 30 days
2. Preliminary Part - 90 days
3. Final Part - 60 days

MMS may require additional operations summaries for deepwater projects. These summaries will be similar to the annual unit operations plan; whereby by operator must provide pertinent information regarding project milestones and achievements, expected operations that could affect the development strategy, and updated reservoir and geologic information obtained from the drilling or completion of additional wells.

1.6.3.9 Reservoir development plan

An additional NTL was issued by MMS addressing the requirements for detailed reservoir management

information. The required information could be submitted with the applicable Development Operations Coordination Document; or at the operator's election, could be submitted as an additional document.

1.6.3.10 Completion operations

Prior to an operator seeking approval via a Sundry Notice of Intent with the MMS District Office, they must first submit a Deepwater Operations Plan. The regulatory process is to submit such a plan prior to commencing acquisition and fabrication of long lead items.

Planning is the key element in the completions phase

Therefore, planning is the key element in this phase of the project. If an operator is proposing to commence completion operations immediately following the cessation of drilling operations, the DWOP must be submitted and reviewed by MMS prior to commencing completion activities. The NTL governing the requirements of these plans, specify that MMS has a time frame of approximately 120 days for the review process.

Timing for return to well to commence production operations

1.6.3.11 Production operations

Another key element in planning when conducting subsea completion operations is the timing for returning to the well for commencing production operations. The current regulations require the testing of underwater valves once every six months. As of this date, MMS has not granted any extensions for testing of these valves once they are originally installed and operational.

1.6.3.12 Abandonment

The process of abandoning deepwater wells is again somewhat different from those on the shelf.

In some cases, operators have obtained approval at the MMS District Office level to utilize explosives for the removal of casings and wellheads. However, it should also be noted, the National Marine Fisheries Service also

requires prior approval due to a potential incidental take of marine mammals.

Variances for removing casings

Additionally, MMS will give consideration towards variances for removing casings the minimal 15 ft below the mud line if several attempts have been made to remove same. These variances are granted on a case-by-case basis and possibly dependent on each district office.

1.6.4 Regulatory Process

The Outer Continental Shelf Lands Act of 1953 and the OCS Lands Act Amendments of 1978 grant to the Department of the Interior (DOI) the primary authority of leasing, and regulating oil and gas exploration, development and production activities on the Outer Continental Shelf (OCS). The OCS is that area beyond 3 nautical miles from the shoreline of the Gulf Coast States of Louisiana, Alabama, Mississippi and 3 marine league miles (approximately 9 miles) from the states of Florida and Texas.

Agencies with jurisdiction over activities associated with oil and gas production

The following agencies have jurisdiction over the exploration and development activities associated with oil and gas production.

Minerals Management Service (MMS)

The OCS Lands Act grants the Department of the Interior the primary authority for leasing OCS lands and for regulating oil and gas exploration, development and production activities on the OCS.

U.S. Coast Guard (USCG)

The Eighth District of the USCG, Department of Transportation has the responsibility for regulating navigation and safety on the OCS, including regulation and monitoring of OCS structures for safety and spills. The USCG sets navigation and safety standards (lighting and

warning devices, fire-fighting and lifesaving equipment, and other safety related devices) for all structures and drilling vessels on the OCS, and conducts periodic inspections to ensure compliance.

Environmental Protection Agency

The EPA is charged with the responsibility for implementing regulations contained in Title 40, governing air and water discharges in OCS Federal Waters, Gulf of Mexico. These operations are governed by either Region VI in Dallas, Texas or Region IV in Atlanta, Georgia.

Corps of Engineers (COE)

Department of the Army is charged with the responsibility of permitting structures installed in navigable waters of the United States.

Research and Special Programs Administration (RSPA)

Department of Transportation is charged with the responsibility for enacting regulations governing the transportation of produced hydrocarbons through certain pipelines, and enforcement of drug and alcohol testing of personnel involved in such operations.

Military Warning Areas (MWA)

The command headquarters of a designated military warning area in the GOM must be contacted prior to initiating exploratory and/or development operations within the area in order to coordinate simultaneous operations with the MWA.

1.6.4.1 Establishing qualifications

Submitting qualification documents

Prior to an individual, corporation, limited partnership, etc. participating in an MMS sponsored lease sale, accepting an assignment of record title interest, royalty interest, operating rights, etc.; qualification documents must be submitted to and approved by the MMS Adjudication Unit, Office of Leasing and Environment.

Regulatory Sources: Title 30 CFR Part 256.35 MMS Oil and Gas Leasing Guidelines

1.6.4.2 Bonding

MMS implements regulations governing the posting of surety bonds or treasury notes to cover potential plug and abandonment liabilities for oil and gas lease activities. This is accomplished through several different procedures.

MMS implements the following levels of bonding:

	Individual Lease	Areawide
Operator Bond	$50,000	$300,000
Plan of Exploration	$200,000	$1,000,000
Development Operation	$500,000	$3,000,000
Coordination Document Supplemental Bonding	Case by case	Case by case

Regulatory Sources

- *Title 30 CFR Part 256.58*
- *Title 30 CFR Part 256.61*
- *MMS Oil and Gas Leasing Guidelines*
  LTL 11-05-93
  NTL 89-07
  NTL 93-2N

1.6.5 Lease Acquisition

1.6.5.1 Lease sale

Five year lease plan

MMS initiates a 5-year lease plan and issues an Environmental Impact Statement for each year's lease sales which result in one each year for both the Western and Central Planning Areas.

Subject to an entity being the successful bidder of an oil and gas lease, the MMS initiates a Phase I and Phase II review process. Typically, if the block passes Phase I, the lease is issued within 3-10 working days; however, if the lease is passed on to Phase II review, it may take 90 days to approve or reject.

Regulatory Sources:
- *Title 30 CFR Part 256*
- *MMS Oil and Gas Leasing Guidelines*

1.6.5.2 Purchase through assignment

Acquisition of a lease from another oil and gas entity

An operator may acquire an oil and gas lease through acquisition from a different oil and gas entity. This would be accomplished and recognized by MMS through the submittal of an oil and gas lease assignment and, if applicable, designation of operator forms executed by all lessees of record and operating rights holders.

Regulatory Sources:
- *Title 30 CFR Part 256*
- *MMS Oil and Gas Leasing Guidelines*

1.6.5.3 Farm-in agreement

All lessees of record designate new company as operator

An operator may negotiate an agreement to drill on a lease under a farm-in type agreement; of which all lessees of record would designate the new company as operator through execution of MMS Designation of Operator Forms. Dependent upon the terms of the agreement and results of the well, an assignment of oil and gas lease would be prepared and executed by all lessees, assigning either record title interest or operating rights interest.

Regulatory Sources:
- *Title 30 CFR Part 256*
- *MMS Oil and Gas Leasing Guideline*

1.6.5.4 Lease Stipulations

Protection of biota

Topographic Features. Prohibits or limits the discharge of drilling effluents to protect the biota of high relief topographic features. Several of these banks are located throughout the OCS Federal Waters of the Gulf of Mexico.

Regulatory Sources:
- *MMS Oil and Gas Lease Form Stipulation*
  NTL 88-11
  LTL 01-31-89

Live Bottom Trends

Seagrass communities, biological assemblages

Additional surveying may be required in the vicinity of live bottom trend areas (typically seen in the Main Pass Area and Viosca Knoll Areas). These live bottom areas are defined as seagrass communities; or those areas which contain biological assemblages (i.e.,sea fans, sea whips, hydroids, sponges, or coral reefs living on or attached to naturally occurring hard or rocky formations).

Regulatory Sources:
- *MMS Oil and Gas Lease Form Stipulation*
  NTL 88-11
  LTL 01-31-89

Military Warning Area

Control electromagnetic emissions

Applied to all blocks in designated military warning areas. The control of electromagnetic emissions must be coordinated between the oil and gas lease operator and the designated military warning area.

Regulatory Sources:
- *MMS Environmental Impact Statements*
- *MMS Oil and Gas Lease Form Stipulation*
  NTL 85-02

1.6.6 Spill Preparedness

See also *Emergency Response, 4.6, Spill Control*

1.6.6.1 *Liability/COFR*

Proof of financial responsibility:
$35 million minimum
$150 million maximum

A responsible party is liable for the total cost of cleaning up a spill, plus $75 million in damages. Operators are required to file proof of financial responsibility in the amount of $35 million. However, MMS has recently signed off on final rulemaking which increases the proof of financial responsibility from a minimum of $35,000,000 to a maximum of $150,000,000 dependent upon the worst case discharge.

Regulatory Sources:
- *Title 30 CFR Part 135.201*

NTL 93-IN

1.6.6.2 Response plan requirements

Contingency planning, training, and drills

Minerals Management Service requires Oil Spill Contingency Planning, Training and Drills prior to and during offshore operations.

Facilities not considered offshore may have requirements for Spill Plans by United States Coast Guard, Environmental Protection Agency, Department of Transportation and States.

Designated personnel required to attend training

Minerals Management Service requires certain personnel named in Continency Plan to attend training. Each company must conduct Spill Management Team Table Top Exercises and Notification drills on an annual basis. In addition, Minerals Management Service has an unannounced Spill Drill Program.

USCG monitors or directs spill response

The United States Coast Guard is the jurisdictional agency that ensures offshore spills are responded to efficiently and efficiently. Depending on the spill size, and efforts by the responsible party, the United States Coast Guard may monitor, direct or federalize the spill.

Regulatory Sources:

- *Title 30 CFR 250.42*
- *NTL 92-04*
- *NTL 97-15*
- *NTL 97-17*
- *LTL 06-06-95*
- *LTL 07-18-95*

1.6.6.3 Miscellaneous OCS plans

Welding and Burning Plans (MMS)

Prior to an operator conducting operations in each MMS District, a general welding and burning plan must be submitted and approved by the MMS District Supervisor. The plan must detail the procedures to be followed in the event of welding and burning outside of designated safe

welding areas, certification requirements, personnel responsible for monitoring such activities.

Regulatory Sources: *Title 30 CFR 250.52*

Simultaneous Operations Plans (MMS)

Prior to an operator conducting simultaneous operations on a facility such as drilling and production, production and construction; personnel must be aware of MMS regulations. MMS does not require the submittal of a detailed plan, but has strongly recommended that each operator implement a general plan and ensure the personnel involved are knowledgeable of the company's policies and MMS regulations.

Regulatory Sources: *Title 30 CFR Part 250*

Waste Management Plans (USCG)

Operator's site-specific waste management plans for manned facilities

Required for all manned facilities in OCS Federal Waters of the GOM. The plan is site-specific to each manned facility, and details the policies of the operator, such as recycling, a no Styrofoam policy, a no burning policy, the handling of waste, disposal sources and recordkeeping requirements. The USCG will look to the owner of the vessel to maintain the garbage log (MODUs and vessels) and to the operators of manned platforms.

Regulatory Sources: *Title 33 CFR Part 151.157*

Hydrogen Sulfide Contingency Plan (MMS)

Required prior to commencing drilling, completion and/or production operations which will penetrate reservoirs known or unknown and/or expected to contain hydrogen sulfide.

Regulatory Sources:
- *Title 33 CFR Art 250.417*
- *NTL 97-09*

1.6.7 EPA NPDES General Permit GMG 290000 Coverage

Prior to issuance of the National Pollution Discharge Elimination System (NPDES) General Permit GMG290000, both Region VI and Region IV operated under NPDES General Permit GMG280000. However, upon the expiration of the NPDES General Permit GMG280000, EPA Region IV area jurisdiction was excluded.

New NPDES being drafted

Region IV is in the process of drafting a new NPDES General Permit, however, during the interim period, the permit was administratively extended only for those operators requesting coverage prior to the expiration date. Furthermore, subject to EPA approval, this coverage may be transferred to another operator. For those operators without coverage under the NPDES General Permit GMG280000, an individual/field application must be submitted. Processing time prior to issuance would be 8-12 months.

1.6.7.1 Coverage

At least 14 days prior to an operator conducting discharge activities regulated under this general permit, coverage must be requested by at least a vice president of the company (or a letter may be executed by at least a vice president, authorizing a certain position to sign all future letters and reports).

Monitoring is accomplished through the guidelines imposed by the subject permit.

1.6.7.2 Annual reporting

EPA will respond to each operator's request for coverage under the general permit by a form letter assigning a sub-permit number specific to that entity. Each area/block where coverage has been requested, EPA will assign an outfall number. The form letter will also state when the

operator must submit annual Discharge Monitoring Reports (DMR).

1.6.7.3 Non-compliance reporting

Report non-compliances within 24 hours of discovery

This is required by EPA under the General Permit. EPA states that non-compliances should be reported within 24-hours after becoming aware of the situation, and dependent upon the situation, EPA may request a written report within 5 days. The Non-Compliance is also reported and detailed on the annual DMR's.

Regulatory Sources:
- *Title 40 CFR Part 435*
- *NPDES GMG 290000 General Permit (Region VI)*
- *NPDES GMG 280000 General Permit (Region IV)*

U. S. Coast Guard Navigational Aids

Required for all above water and certain below water structures and obstructions

These aids are required for all above water and certain below water structures and obstructions. The USCG will require an operator to submit an application detailing information relative to the structure, i.e., location coordinates, details of the structure, information pertaining to the navigational aids to be installed, and the individual charged with responsibility for maintaining the aids.

Regulatory Sources: *Title 33 Part 67*

Emergency Evacuation Plans

Required for all manned facilities in OCS Federal Waters

Emergency evacuation plans are required for all manned facilities in OCS Federal Waters (MODUs and Platforms). The plan must be submitted to the appropriate USCG MSO prior to initiating activities. The plan must detail specifics on the manned facility, i.e., location coordinates, telephone numbers, support vessel information, response team personnel with 24-hour telephone numbers and response center location, etc. and how the facility will be evacuated in the event of an emergency situation, such as an impending hurricane, uncontrolled well, man overboard, etc.

Regulatory Sources: *Title 33 CFR Part 146.140*

Rig Movement Reports

Rig movements must be reported to the USCG prior to moving on and off locations with mobile offshore drilling units.

Regulatory Sources: *Title 33 CFR Part 146*
MMS Conditions of Approval to Drill

Waste Management Plans

Waste management plans are required for all manned facilities in OCS Federal waters (MODUs and Platforms). The plan must be prepared in accordance with the criteria outlined in the code of federal regulations (as a result of MARPOL 73/78) and be implemented and in-place on each manned facility.

Prohibitions and limitations of garbage disposal and transport to shore

The purpose of the plan is to ensure that personnel are aware of the prohibitions and limitations of garbage being thrown overboard, and of the manifest requirements when transporting to shore for ultimate disposal.

Regulatory Sources: *Title 33 CFR Part 151.157*

Minerals Management Service

High Resolution Geophysical Surveys

Prior to any drilling activity or the construction or placement of any structures on a lease block, a high resolution geophysical survey must be conducted and submitted to MMS for approval. The purpose of this survey is to provide information on potentially hazardous conditions that could adversely affect the safety of surface disturbance operations.

Regulatory Sources: *Title 30 CFR Part 250.203*
NTL 83-3
LTL 06-21-91

Cultural Resources Study

Archaeological resource report

After a lease is issued, MMS will notify the operator in writing of the decision to actually invoke the archaeological resource report requirement of the lease stipulation. Identification will be made to the operator of the type of report (historic shipwreck, historic shipwreck/prehistoric site, or prehistoric site) and the standards that shall be required for compliance.

Regulatory Sources:
Title 30 CFR Part 250, 256, 280 & 281
LTL 11-30-90
NTL 91-02
LTL 03-17-95
LTL 09-05-95

1.6.8 Exploration Operations

1.6.8.1 Plan of Exploration (POE)

Prior to an operator conducting exploratory drilling operations, a plan (initial, revised or supplemental) must be submitted to MMS for review and approval.

This plan must address description of work to be performed, type of drilling unit, well locations, structure maps, cross section maps, stratigraphic columns, bathmetry maps, information relative to spill response issues, shallow hazards analyses for each proposed surface disturbance, presence or absence of hydrogen sulfide, information on mud additives and discharge volumes, air quality emissions report, environmental report and coastal zone consistency certification.

Regulatory Sources:
Title 30 CFR 250.203
Title 30 CFR 250.171
NTL 86-09
LTL 10-12-88
LTL 09-05-89
LTL 09-27-89
LTL 11-02-92
LTL 12-31-91

LTL 11-05-93
NTL 94-02
LTL 05-05-94
LTL 08-31-94
NTL 94-04
LTL 05-02-94
LTL 01-06-95
LTL 03-17-95
NTL 97-03
NTL 97-10

1.6.8.2 Application for Permit to Drill (APD)

Each proposed drillsite must be provided for and approved under a POE or a DOCD before MMS can approve an APD. This application must address the general drilling procedure, mud, cementing, BOP, and logging and coring programs, and pressure programs.

Changes to the approved APD may require verbal and/or written approval from the MMS

Any changes to the approved APD may require verbal and/or written approval from the appropriate MMS District Office prior to initiating the change. This is accomplished through the submittal of a Sundry Notice of Intent form.

If verbal approval is obtained, the form must be submitted within 72 hours. During the actual operations, weekly progress reports and additional Sundry Notices must be submitted as warranted. Upon completion of operations, a Sundry Notice Subsequent and Well Summary Report must be submitted to MMS.

Regulatory Sources: *Title 30 CFR Part 250.414*
Title 30 CFR 250.171
LTL 01-14-94
LTL 11-17-94
LTL 01-25-95
NTL 97-2N
NTL 97-07
NTL 97-16

1.6.8.3 Sundry Notices

Sundry Notices are required for any changes to the approved Application for Permit to Drill, subsequent verbal approvals on abandonments, completions, workovers, etc.

Regulatory Sources: *Title 30 CFR Part 250.65*
Title 30 CFR Part 250.171
Title 30 CFR Part 250.172
Title 30 CFR Part 250.176
NTL 97-07
NTL 98-2N

1.6.8.4 Well Summary Reports

These reports must be submitted to provide notice of current well status and specific casing program, perforation program, geological markers. Supporting data include well logs and wellbore surveys (i.e., directional surveys, sidewall core analysis, velocity surveys).

Regulatory Sources: *Title 30 CFR Part 250.66*
NTL 91-01
LTL 10-01-90
LTL 10-30-95

1.6.8.5 Flare and Burn Requests

Approval must be obtained from MMS prior to commencing flaring of gas for periods extending 48 hours, and for the burning of any liquid hydrocarbons.

Regulatory Sources: Title 30 CFR Part 250.1105
NTL 95-01

1.6.9 Development Operations

1.6.9.1 Development Operations Coordination Document (DOCD)

The DOCD is required prior to initiating certain development activities on an oil and gas lease, typically the installation of a permanent multi-well platform, installation of a lease pipeline, and/or development drilling operations. This plan must contain certain detailed information.

DOCD typically concerns installation of a permanent multi-well platform, lease pipeline, and/or development drilling operations

MMS classifies a pipeline installed within the boundaries of a block, or combination of blocks where there is common operatorship as a lease pipeline. If any portion of a route crosses a block or combination of blocks where the operatorship is not common, the pipeline will be classified as a right-of-way pipeline.

Regulatory Sources: *Title 30 CFR Part 250.204*
Title 30 CFR Part 250.171
LTL 09-05-89
LTL 09-27-89
LTL 10-12-88
NTL 86-09
LTL 11-02-92
LTL 05-02-94
LTL 05-05-94
LTL 08-31-94
NTL 94-02
LTL 03-17-95
LTL 01-06-95
NTL 94-04
NTL 97-10
NTL 98-13N

1.6.9.2 Reservoir Development Plan

Conservation information for development of economically producible reservoirs

An operator must submit conservation information to MMS to ensure development of economically producible reservoirs in accordance with sound conservation, engineering, and economic practices before committing or expending substantial funds. This information can be submitted as part of the Supplemental Plan of Exploration, Initial or Supplemental Development Operations Coordination Document, or the submittal of a separate document. The proprietary information must address each reservoir encountered during the drilling of the well(s) which quality as capable of producing in paying quantities in accordance with Title 30 CFR 250.1111.

Regulatory Source: *Title 30 CFR Part 250.202*
Title 30 CFR Part 250.1101
NTL 98-14N

1.6.10 Deepwater Operations Plans

A three phase submittal (Conceptual, Preliminary and Final) providing an overview of the development strategy of deepwater wells.

1.6.10.1 Conceptual

The Conceptual Part identifies the concept for field development and the basis for engineering design:

4. Location Plat
5. Facility Description
6. Description of Drilling/Completion System
7. Description of Pipeline System
8. Description of Drilling, Production and Export Riser Systems
9. Description of Subsea Control System
10. Expected Production Stream Composition
11. Anticipated Shut In Tubing Pressure
12. Special Production Situations
13. Identification and Description of Known Hazards and Unusual Conditions
14. Application of New Technology
15. Abandonment of the Facilities

1.6.10.2 Preliminary

The Preliminary Part describes changes to the development concept presented in the Conceptual Part, and emphasizes any areas of the design, fabrication and installation of the system and/or components that incorporate new technologies or will require alternative compliance or departures.

1. Wellbore Information
2. Structural Information
3. Mooring System
4. Station Keeping Systems

5. Drilling and Completion Systems
6. Riser Systems
7. Pipelines
8. Vessel-Based Offtake Systems
9. Subsea Systems
10. Surface Production (Process) Equipment
11. Emergency and Safety Systems
12. Production Allocation Test
13. Operating Procedures
14. Installation and Commissioning and Testing
15. Hazards Analysis

1.6.10.3 Final

The Final Part updates information submitted in the Conceptual and Preliminary Parts:

1. Listing of Differences from Previous Conceptual and Preliminary Parts
2. Cover Letter

Regulatory Sources: *NTL 98-8N*

Platform Applications

Caissons and platforms installed over or adjacent to existing wells require approval from MMS. Such applications must include the engineering design, environmental load information, structural load information, construction drawings, soil analysis and surface location information.

Regulatory Sources: Title 30 CFR Part 250.900
NTL 97-05
NTL 98-1N
NTL 98-4N
NTL 98-07N
LTL 05-14-91
LTL 01-06-95

Surface Safety System Installations

Prior to installation, an application must be approved relative to the design and installation features of production and processing vessels, including process flow diagrams, area classification drawings, SAFE Charts, and applicable waivers (time delays, chemical fire fighting equipment).

Regulatory Sources: *Title 30 CFR Part 250.120*
LTL 04-04-91
NTL 97-09
NTL 97-17
NTL 98-2N

Pipeline Applications

Pipeline installation

Prior to installation of any lease and/or right-of-way pipelines, an application must be submitted relative to the engineering design of the pipeline, hazards analysis, and notifications to affected operators and/or right-of-way holders, proposed route plats and pipeline safety schematic.

Regulatory Sources: *Title 30 CFR Part 250.1009*
NTL 92-04
LTL 04-18-91
NTL 83-03
NTL 91-02
LTL 01-06-95
NTL 97-08
NTL 97-09
NTL 96-10

Surface Commingling/Measurement Authority

Commencing production

Approval is required prior to commencing production from a lease to address the surface measurement and commingling procedures for the gas and liquid hydrocarbon production; addressing the sales and royalty points for these hydrocarbons, and the lease/well allocation methods.

Regulatory Sources: *Title 30 CFR Part 250.181*
Title 30 CFR 250.182
NTL 98-17

Abandonment Operations

Prior to an operator initiating abandonment operations, a Sundry Notice of Intent must be submitted to conduct wellbore operations, with separate applications submitted to remove the structure and abandon the pipeline. These applications must detail the method of abandonment and removal.

Regulatory Sources: *Title 30 CFR 250.704*
NTL 92-02

Site Clearance Verification

Seafloor must be clear of all obstructions after structure removal

Upon removal of structures, the seafloor bottom must be cleared of all obstructions.

The distance requirement varies dependent upon the type of structure installation. Part of this procedure requires the operator to trawl the site in the pre-determined radius for those leases in water depths of 300 feet or less.

A site-clearance verification plan must be submitted to MMS prior to initiating these operations, which includes the contractors to be utilized, trawling vessel information, navigational instrumentation, etc.

Regulatory Sources: *Title 30 CFR 250.913*
NTL 92-02

1.6.11 Typical Departures/Alternative Compliance for Deepwater Projects

MMS Regulation	Departure / Alternative Compliance
250.51(h)	Emergency shut down station installed near the driller's console
250.57(e)(3)	BOP equipment testing interval
250.87(c)	Casing annuli monitoring requirement
250.87(d)	Pressure rating of tree, wellhead, and related equipment (SITP vs. SCSSC operating pressure)
250.107(d)	Pressure rating of tree, wellhead, and related equipment
250.112(I)	Permanent abandonment of wells - clearance of location
250.113	Temporary abandonment of wells
250.121(e)(4)	SCSSV installation, maintenance, and testing requirements
250.121(I)	Closure of SCSSV in response to ESD (and fire detection system activation requirements)
250.122(b)	Subsea flowline FSV requirements (Ref: API RP 14C A1.2(b)(2) and Figure 1-A.1.2)
250.122(d)	USV installation, maintenance, and test requirements
250.123(b)(2)(I)	PSHL set point requirements (for subsea pressure sensors)
250.123(b)(4)ii)	USV and SCSSV closure time requirements
250.123(b)(11)	Erosion control program requirements
250.124(a)(1)(I)	SCSSV function and leak test (interval and criteria)
250.124(a)(3)(I)	PSHL device test requirements (interval for subsea pressure sensors)
250.124(a)(3)(iii)	SDV operations test requirement (interval)
250.124(a)(4)	USV leak test requirements (interval and criteria)
250.124(a)(5)	Subsea FSV leak test requirements (interval and USV/SCSSV closure)
250.124(a)(10)	ESD operation test requirements (interval and USV/SCSSV closure)
250.126	Safety and Pollution Prevention equipment quality assurance requirements
250.152(a)	DOI pipelines internal design pressure calculation (e.g., use external pressure)
250.152(b)	Pipeline valves, flanges and fitting requirements (e.g. cold temperature effects)
250.154(b)(6)	Subsea tie-in FSV requirements
250.156(a)(1)	Abandonment requirements for DOI pipelines
250.174	Bottomhole pressure survey requirements

Table 1- 12 Typical Departures/Alternative Compliance for Deepwater Projects

MMS Deepwater in the Gulf of Mexico: America's New Frontier (OCS Report MMS 97-0004)

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CHAPTER 1. WELL PLANNING INDEX

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2.0 WELL CONTROL PROCEDURES

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Chapter 2. Well Control Procedures

Well Control Procedures Subcommittee
Mike Briggs (Chairman) – Noble Drilling Company
David Bruce – Diamond Offshore Drilling Company
Stan Chrisman – Exxon Upstream Development Company
Larry Flak – Boots & Coots IWC
Doug Foster – Diamond Offshore Drilling Company
Allen Gault – Conoco, Inc.
Kerry Girlinghouse – Chevron USA
Ronald James – Diamond Offshore Drilling Company
Allen Kelly – Diamond Offshore Drilling Company
Colin Leach – Well Control and Systems, Inc.
Benny Mason – Unocal
Steve Moore – Conoco, Inc.
Chris Nelson – Newfield Exploration Company
Shiniti Ohara – Petrobras
Steve Ramsey – Diamond Offshore Drilling Company
Mike Rogers – R&B Falcon Drilling Company
Alan Wittry – Phillips Petroleum Co.

BHP	Bottomhole pressure
BPM	Barrels per minute
C&K	Choke and kill lines
CLFP	Choke and kill line friction pressures
DP	Dynamically positioned
DPO	Dynamic positioning operator
ECD	Equivalent circulating density
EDS	Emergency disconnect sequence
FOSV	Full opening safety valve
GOM	Gulf of Mexico
HEP	Hurricane evacuation plan
IBOP	Internal blowout preventer
LCK	Lower choke and kill lines
LMRP	Lower marine riser package
LWD	Logging while drilling
MODU	Mobile offshore drilling unit
MWD	Measurement while drilling
OBM	Oil-base mud
PWD	Pressure while drilling
SBM	Synthetic- base mud
SICPP	Shut-in casing pressure
SIDPP	Shut-in drill pipe pressure
SWF	Shallow water flow
UCK	Upper choke and kill lines
VBR	Variable bore ram
WBM	Water-base mud

CHAPTER 2. WELL CONTROL PROCEDURES
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2.1 Kick Prevention & Detection

2.1.1 Summary

Kick warning signs same in deepwater

The standard well kick warning signs are the same in deepwater as in shallow water:

- Flow rate increase (delta over 15-30 sec. 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

2.1.2 Mud Density

No riser margin in deepwater

See also *Well Planning, 1.3, Drilling Fluid Considerations*

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").

Synthetic and oil-based muds compared to water-based muds

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 includes 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.

2.1.3 Mud Viscosity

Viscosity increase can mask SICP

Viscosity increase in choke and kill (C&K) lines due to length and low temperature can mask shut-in casing pressure (SICP). This effect is increased with synthetic muds that have high viscosity at low temperature. Kick detection may be difficult, as the well may flow during flow checks, but have no shut-in casing pressure.

Options for reducing viscosity

An option in order to reduce viscosity is to fill C&K lines with a clear or gelled fluid. In making this decision, one should consider the effects of mud solids settling in the C&K lines and the resulting plugging or loss of hydrostatic pressure.

One may circulate the C&K lines several times per day to reduce the potential for settling of solids (unless they contain a clear fluid).

Breaking circulation

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 when breaking circulation.

2.1.4 Drilled Cuttings

Riser 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. This becomes especially important if the booster line is not available or is not used.

Pressure while drilling equipment

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 BOP stack can provide much of this information.

Increased lag time

2.1.5 Abnormal Pressure Detection

Lag time for gas units and cuttings increases in deepwater, reducing the timeliness of this data for abnormal pressure detection purposes.

Mud temperature effects

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 decrease in other detection capabilities.

2.1.6 Environmental Effects

Pitch, roll, and heave motions

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.

2.2 Shut-in

2.2.1 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 both drill pipe friction loss and both C&K Line Friction Pressures (CLFP). • 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. • Insure that cuttings in 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 static C&K line or subsea BOP pressure sensor (See 2. 3, Circulating To Kill). *Note: Slow pump test rates should represent anticipated kill rates (which may be as low as 1-2 BPM in deepwater).*
C&K line friction pressures	• Use CLFP to help establish initial circulating casing pressure (See 2. 3, Circulating to Kill). • Recognize that in deepwater the CLFP is likely to change such that test data are only estimates. • Measure and record pressure losses with low circulation rate through the lines in parallel.* **One option to reduce friction losses during well control in deepwater wells is to circulate the kick using the two choke and kill lines in parallel (see 2.3.5, Number of C&K Lines).*
Kill sheet	• Maintain an up-to-date kill sheet designed for subsea 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 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.*

Continued on following page

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C&K line valve positions	• Show C&K line valve positions on a chart/white board indicating which valves are open/closed and C&K line fluid contents (mud versus water). • Show the relationship between the surface tool joint location and corresponding tool joint location opposite the BOP stack rams and annulars. • Calculate and post the distance and proper spacing for each stand to help with space-out, if variation in stand length warrants. *Note: As water depth increases, the variation in drill pipe joint length can create too much uncertainty in tool joint position; this potential problem can be reduced by arranging joints so that 10-stand average lengths do not vary by more than a set amount, i.e., 0.1 feet.*
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 and C&K line geometry, i.e., pumping rate, design kick.
Diverter	• Keep diverter insert packer installed and locked except when handling BHA larger than manufacturer's stated diameter capacity. • Post diverter element status (in/out).
Designated hang-off ram	• 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).
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.

Table 2-1 Pre-kick preparation.

2.2.2 Hard Shut-in versus Soft Shut-In

Soft/Hard shut-in issue is same as shallow water

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 (See Reference IADC/SPE 25712).

2.2.3 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:

Shut-in Approach	Favorable Factors
Annular shut-in	• Eliminates the need to insure tool joint is not near the BOP ram (increasingly difficult in deepwater due to vessel offset effect on length, more joints of pipe to consider). • Provides a means to effectively shut-in while still allowing for movement of the drill pipe to reduce sticking of the drill string.
Shut-in and hanging-off operation with a ram	• Allows well to be closed in more quickly • Minimizes amount of gas that may be trapped in the BOP. • May provide higher pressure rating than annulars. • Ensures that sticking will not preclude hanging off the drill pipe. • Being hung-off, the well is ready for emergencies, e.g., severe weather, drive-off, mooring failure, loss of riser, etc. • 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. • Minimizes amount of gas that may be trapped below annular. • Minimizes chance that sticking will preclude hanging off the drill pipe. • May provide higher pressure rating than annulars. • Being hung-off, the well is ready for emergencies.

Table 2-2 Annular shut-in vs ram shut-in.

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 (SPE 26952).

2.2.4 Shut-In While Drilling

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

Step	Action
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 spaceout.
2	Stop the mud pumps and check for flow. Ensure that the riser boost valve is closed. *Note: a gas influx may have risen above the BOP, given deepwater conditions (See 2.6, Gas in Riser).*
3	Close the selected BOP.
4	While the BOP is closing, open selected subsea C&K line valves. *Note: C&K line should now be lined up to the pre-selected choke.*
5	Monitor for flow from the riser. Consider closing the diverter as a precaution against gas in riser. *(See 2.6, Gas in Riser)*
6	Check for surface leaks. Alert the supervisor.
7	Read and record shut-in drillpipe (SIDPP), shut-in casing pressure (SICP) on both C&K lines, and pit gain. Monitor and record this data periodically.
8	If hang-off is desired, it can be initiated now. *(See 2.2.10, Hang-off Guidelines)*

Table 2-3 Shut-in while drilling.

2.2.5 Shut-In While Tripping

Full opening safety valve

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.

Step	Action
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. Check for flow. *Note: The riser boost valve should be closed.*
4	While the BOP is closing, open selected subsea C&K line valves. *Note: The choke flowline should now be open through to the closed pre-selected choke.*
5	Monitor for flow from the riser. Consider closing the diverter as a precaution against gas in riser. *(See 2.6, Gas in Riser)*
6	Check for surface leaks. Alert the supervisor.
7	Read and record shut-in drillpipe (SIDPP), shut-in casing pressure (SICP) on both C&K lines, and pit gain. Monitor and record this data periodically.
8	Prepare to strip back to bottom with an annular BOP.

Table 2-4 Shut-in while tripping.

2.2.6 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 (See Table 2-4 above). Hang-off depends on rig specific considerations.

2.2.7 Shut-In with Bit above the BOPs

Out of the hole or inside riser:
- **Using blind/shear rams**
- **Avoiding gas in riser**

If kick indicators occur while out of the hole or inside riser, the first action should be to shut-in with the blind/shear rams. It is important to close in as quickly as possible to avoid gas in the riser.

The following table contains an example procedure for shut-in with the bit above the BOPs.

Step	Action
1	At the first indication of flow from the well, close the blind/shear rams.
2	While the BOP is closing, open selected subsea C&K line valves. *Note: C&K line should now be aligned with the preselected choke.*
3	Monitor for flow from the riser. Consider closing the diverter as a precaution against gas in the riser. *(See 2.6, Gas in Riser)*
4	Check for surface leaks. Alert the supervisor.
5	Record shut-casing pressure (SICP) on both C&K lines, and pit gain. Monitor and record this data periodically.
6	If drill pipe is hung-off on the slips, be alert for potential fatigue damage from vessel pitch and roll.
7	Prepare for stripping and bullheading operations. Implement volumetric pressure control if necessary.

Table 2-5 Shut-in with bit above BOPs.

2.2.8 Shut-in while Running Casing/Liner

Location of shoe and hanger

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 is inside the riser
- casing/liner inside the BOPs
- hanger is below the BOPs
- drill pipe is in a position that allows the well to be shut-in

Crossover connection between drill pipe and casing/liner

If a kick is possible with the casing/liner in the well and also at the rig floor, a crossover is needed to connect drill pipe to casing/liner.

2.2.9 Masking of Casing Pressure by High Gel Strength in C&K Lines

Depending on the results of the slow circulation rate test for C&K line friction pressures (CLFP), the gel strength of the fluid in the riser may mask shut-in casing pressure (See 2.2, Shut-in). If so, there is a procedure to break the gel strength:

Step	Action
1	Close another BOP so that there is a C&K circulation path between the two closed preventers.
2	Align the subsea C&K valves to isolate the well and set up a flow path between the two BOPs.
3	Circulate the C&K lines to break the gel strength.
4	Stop circulating and reopen a C&K valve to well below the BOP to determine casing pressure.

Table 2-6 Procedure to break gel strength.

2.2.10 Hang-off Guidelines

On floating rigs, hanging-off on designated hang-off rams is an essential part of the close-in and kill procedure. The tool joint must not be placed opposite shear rams.

Spacing and landing the drillstring

Tool joint placement

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.

Circulating head

If a circulating head is to be used in well kick operations, the hang-off procedure will include the installation of a circulating head.

The table on the following page 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:

Consider hanging-off drillstring IF:	Comments
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	• Can result in wear damage to the annular BOP element
Using dynamic-positioned rig where drift-off potential exists, or where a mooring line failure 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 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
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)
Riser angle at the Lower Marine Riser Package is greater than established operating limit	
Surface flow from the riser indicates that annular preventer may be leaking formation fluid or gas above the BOP stack	
Unable to establish full returns, or evidence of an underground flow exists	
Casing pressure increases above operating limits for the annular with/without drill pipe movement	

Table 2-7 Hanging-off the drillstring.

2.3 Circulating to Kill

2.3.1 Summary

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

Factor	Consideration
Gas	• Gas migration/location at shut-in relative to casing shoe
Circulation rate	• Slow pump data, rate selection • Consider reducing circulating rate as influx and kill weight mud approach BOP stack and C&K lines (to offset increasing pressure on casing shoe) • Need to adjust DP pressure for new rate, using static line pressure if available, or otherwise active line pressure • Decision to circulate up one or two choke lines
Mud	• Mud viscosity data and effects • If C&K gel strength is high (See 2.2, Shut-in) and mud weight/formation integrity margin is low, consider breaking C&K circulation as described in 2.2.9
Frac gradient	• Typically will be lower in deepwater
Mud/Gas separator loading	• May be higher in deepwater

Table 2-8 Factors related to methods of circulating a kick to surface.

2.3.2 Driller's Method

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

Driller's method advantages

- circulation brings wellbore heat up the BOP and C&K lines, helping to keep temperatures above hydrate temperature
- reduced time and potential for hydrates to form (kinetics effect)
- circulation tends to keep BOP equipment temperatures somewhat higher than a static well

2.3.3 Wait & Weight (Engineer's) Method

Advantages of the Wait & Weight Method include:

Wait & weight method advantages

- 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.

2.3.4 Bullheading

Bullheading may be a viable alternative unless the open hole section is lengthy. Forcing influx fluids down the wellbore may induce underground interzonal flow.

However, bullheading may be best choice if other options would exceed pressure limits or excessive hydrogen sulfide is expected and if hole situation is favorable.

2.3.5 Number of C&K Lines

The two C&K lines provided on floating rigs offer the following purposes and uses:

Options with a second C&K line

- Back-up for first line (plugs, leaks, etc.)
- In deepwater, can be used as a static line to monitor BOP pressure to compensate for C&K line friction (a BOP pressure sensor can be used for this, if available)
- Circulate a well that is hung-off with the drill pipe disconnected below closed blind rams)
- Circulate across closed BOP (trapped gas)
- Pump through both C&K lines to reduce friction loss

Circulating up both C&K lines reduces friction:

Circulating up both C&K lines

- Reduces friction by about 50-75 percent for same circulation rate
- Reduces casing shoe loads at zero surface pressure, i.e., at end of kill
- Precludes use of second C&K line to monitor BOP pressure

2.3.6 BOP "Separator" Effect

BOP stack as gas/mud separator

Using two C&K lines allows the BOP stack to act as a gas/mud separator, assuming that the gas and mud are in two phases, i.e., not dissolved.

The diagram on the following page illustrates the BOP separator effect:

BOP SEPARATOR EFFECT

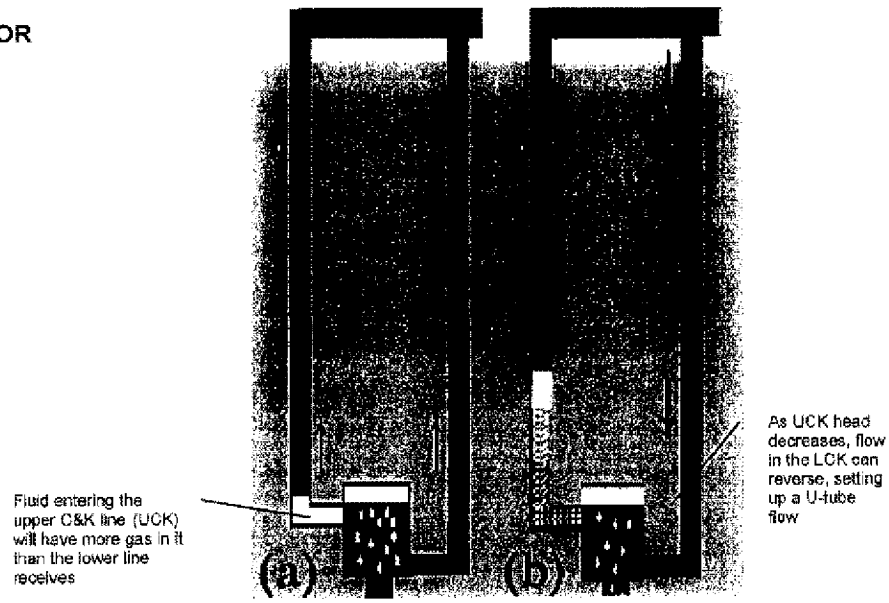

Figure 2-1 BOP separator effect.

As shown in the above figure, the advantages of the BOP separator effect are as follows:

- Gas will preferentially rise to the top of the BOP cavity such that fluid entering the upper C&K line (UCK) will have more gas in it than the lower line receives, as shown in Figure 2-1(a).
- As this happens, the head in this line will be less.
- Therefore, the UCK will take a greater proportion of the total flow, i.e., higher rate.
- As UCK head decreases, flow in the lower C&K line (LCK) can reverse, setting up a U-tube flow, as shown in Figure 2-1(b)

This flow of mud from the LCK is then added to the flow of gas from the wellbore, so that fluid entering the UCK has more mud in it.

The net effect is to reduce the potential swapover of a C&K line to gas and head loss.

Net effect: reduces the potential swapover of a C&K line to gas and head loss

This affects surface pressure behavior which the person operating the choke has to control.

Use of two C&K lines reduces the fluctuations in surface pressure, and hence the degree of choke change reactions, as shown by the example case below.

The BOP separator effect is not applicable if the gas is dissolved, i.e., in synthetic-based mud.

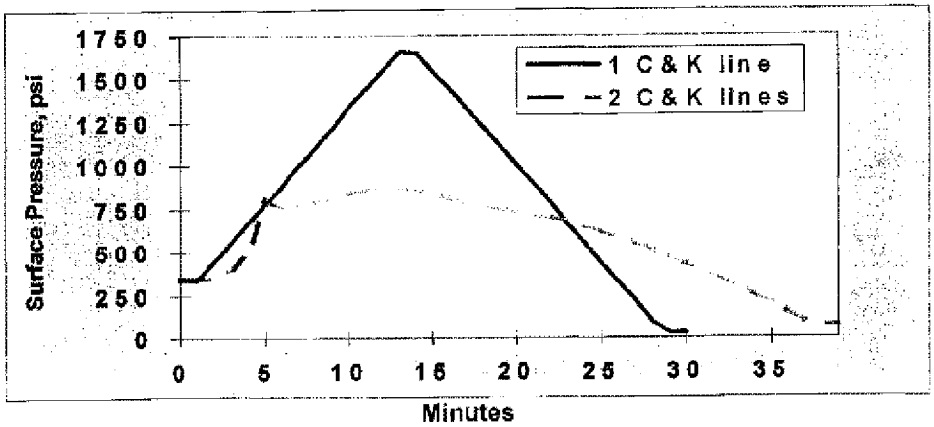

Figure 2-2 BOP separator effect: example case.

2.4 Preventing Lost Returns and Underground Blowouts

2.4.1 Summary

Booster pump and riser booster line

In deepwater with long riser and high penetration rates, equivalent circulating density can increase significantly due to cuttings loading (slip velocity). A booster pump and riser booster line can be used to increase riser velocity and hence reduce the loading problem.

See Procedure Diagram on following page.

2.4.2 General Procedures for Detection of an Underground Blowout

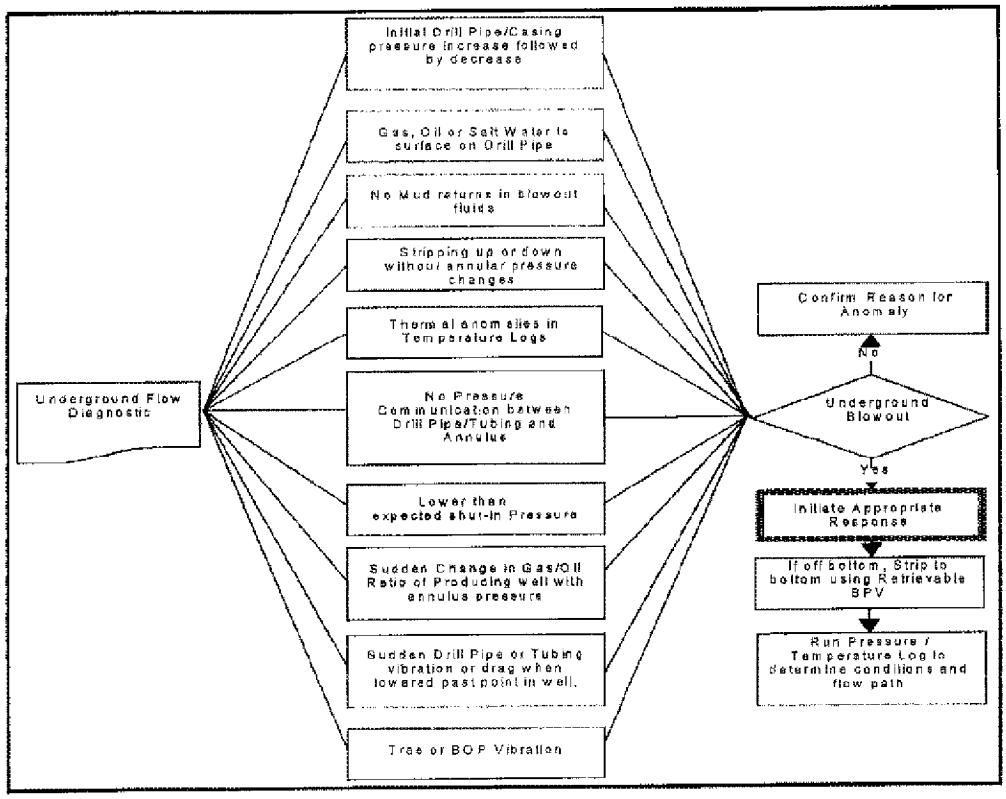

Figure 2-3 General procedure for the detection of an underground blowout.

2.4.3 Underground Blowout while Drilling

Indicators of an underground blowout while drilling include the following:

Indicator	Observation
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 and/or BOP ratings, fluid (mud or water) can be pumped into the annulus to keep annulus pressure down.*
Gas displacement	• If there is no float in drillstring, some DP mud may be displaced with gas if 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 same pressure as downhole flowing pressure (less gas head), and may exceed casing pressure rating. A response action to prevent this is to pump seawater 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.
Annulus pressure	• Able to strip drill pipe with no change in annulus pressure.

Table 2-9 Underground blowout detection while drilling.

2.4.4 Detection of an Underground Blowout while Producing or Working Well Over

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

Indicator	Observation
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 BOP vibration on shut-in well. • Sudden tubing or drill pipe vibration and/or drag when lowered past point in well.

Table 2- 10 Underground blowout detection while producing or working over a well.

2.4.5 Actions/Considerations in the Event of an Underground Blowout

Action/Consideration	Comments
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.
Send personnel to look for broaching in immediate area if underground flow is indicated.	• Visual • ROV
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 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 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 were to bridge off and the drill pipe float valve (if installed) failed.
If needed to keep annulus pressure below casing pressure limits, pump seawater or mud down C&K lines into casing.	• Keeps casing from completely filling up with migrating gas.

Table 2- 11 Actions/Considerations in the event of underground blowout.

2.4.6 Riser Damage

Leakage from riser

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).

Checking for riser mud loss

One way to check is to close a preventer and monitor while circulating slowly via C&K lines. If there is no circulation, then hole is losing mud. Or if riser level will not stand full, then riser system is leaking.

Riser buckling can be caused by insufficient tension, and can create a split and hole at the buckle point.

2.4.7 Riser Tension

Riser design criteria API RP 16Q suggests setting tension high enough to allow for two tensioners to fail and still retain adequate tension to keep riser in tension. Where each tensioner has an independent power system, this allowance is often reduced to failure of a single tensioner.

In deepwater, riser tension can be lost due to equipment failure or temporarily removing tensioners from service

A significant portion of the riser tension can be lost either due to equipment failure or the need to temporarily remove tensioners from service.

If this occurs, consider closing the BOP and replacing the riser mud with seawater to reduce tension requirements. Note that the drill string can provide some of the lost tension, as follows. The riser can be partially supported by contacting the drill pipe. The drill pipe tension can roughly replace riser tension on approximate a pound-for-pound basis, via lateral contact between the drill pipe and the riser.

Extreme cases

In extreme cases where the hanging tension of the drill pipe is not enough, consider the following option:

1. Close a pipe ram around the drill pipe
2. Pull a tool joint up against the ram with the motion compensator.
3. Increase the compensator setting to get more tension (within DP tension rating and BOP limits of hang-off capacity).

Pulling out of the hole eliminates drill pipe support, results in loss of riser integrity

In any case, pulling out of the hole can cause loss of whatever drill pipe support exists and cause loss of riser integrity.

2.5 BOP Cleanout (Trapped Gas)

2.5.1 Summary

During well control of a gas influx with a subsea BOP stack, gas may accumulate in the space between the closed preventer and the outlet used for circulation. This gas is called 'trapped gas'.

It has created known problems in water depths of about 1,000 to 2,500 feet. The potential for problems in deeper water has not been fully explored due to limited operational experience and analysis limitations.

Trapped gas volume factors:
- **BOP arrangement**
- **BOP diameter**
- **Gas/Mud dispersion and separability**
- **Drilling fluid type**

The volume of trapped gas will depend on the BOP arrangement used, the diameter of the BOP, the dispersion/separability of the gas and mud, and the type of drilling fluid.

Synthetic-based muds (SBM) and oil-based muds (OBM) can absorb a considerable amount of gas, which may not evolve back from the mud until the pressure is below the pressure in the BOP, i.e., in the riser or even downstream of the surface choke.

Trapped gas effects and water depth

The effects of trapped gas have a strong dependence on water depth. The pressure of the trapped gas will be the mud hydrostatic pressure, and the deeper the water, the higher this pressure will be. The higher the pressure, the greater the expanded volume of this gas when it reaches the surface.

For example, in 1500 feet of water with 12.0 ppg mud, the pressure would be 950 psia. For an 18-3/4 inch BOP with a 15-foot distance between the annular (assumed shut-in BOP) and the upper choke outlet, the trapped gas volume could be 5 bbls. If this 5 bbls of gas migrates as a single gas bubble to the surface, it expands to over 300 bbls (ideal gas basis).

Bubble rise characteristics

The characteristics of the bubble rise are important to appreciate. At first, the upward velocity will be simple migration, perhaps tens of feet per minute (plus circulating annular velocity), with slow expansion.

Critical bubble depth often 100-300 ft

There is a critical bubble depth at which it becomes capable of pushing the mud above it out of the riser, and the migration turns immediately into a rapid expansion and release of the gas out of the riser. This critical depth is a function of gas bubble size and mud density, but is often a depth of 100 to 300 feet.

The riser may lose the entire expansion volume of mud, e.g., 300 bbls, dropping its level several hundred feet. Such a drop could underbalance a formation in the wellbore if the BOP is open (See Chapter 2.6, Gas in Riser).

2.5.2 Field Test Results

Directionally, the trapped gas issue increases with water depth, since its pressure increases. However, there is field test data that indicates that there is an offsetting effect that reduces the problem potential.

Field test

1. **Trapped gas placed below closed BOP**
2. **BOP opened to allow gas migration**

The test was run in ± 3100 ft of water with a 13.2 ppg density mud. Trapped gas (air) volumes of 10 to 50 bbls were placed below a closed BOP, and then the BOP was opened to allow the gas to migrate. In each case, the air did not migrate as a slug, but rather dispersed itself. It did not displace a large volume of mud from the riser.

Results

- **Gas dispersed (no slug)**
- **Did not displace large volume of mud from riser**

The 30 bbl air volume test (equivalent to 110 ft BOP/choke outlet distance in the 16-3/4 inch BOP) unloaded only 19 bbls of mud from the riser.

Surface observations of the returns were small "boiling" bubbles, air-cut mud, and minor slugging.

Tests were also conducted circulating out trapped gas of 10 and 30 bbls at 6 BPM. The 10 bbl test still strung out the

bubble and did not unload any mud. The 30 bbl test unloaded over 100 bbls of mud, indicating that the circulation rate brought some of the large bubble up before it could disperse. Problems associated with the trapped gas phenomenon may be significantly reduced in deeper water (3,000 ft +)

Problems associated with trapped gas may be reduced in deepwater with water-base mud and appropriate circulation rate

From these tests, it appears that problems associated with the trapped gas phenomenon may be significantly reduced in deeper water (3,000 ft +) with water-base mud and if the circulation rate is not too high. With synthetic and oil-based muds, evolution of dissolved gas in the riser remains an important consideration for all water depths.

Although the tests show a reduced potential, they are not conclusive for all conditions. In water depths shallower than 3,000 ft, trapped gas can be a potentially significant problem requiring special procedures to handle. For handling trapped gas, the items and questions listed below should be considered:

2.5.3 Equipment Considerations

1. Stack configuration
2. Location of outlets (choke and kill)
3. Condition of annular (will affect ability to hold differential across element)
4. Surface gas handling capacity
5. Is there a C&K line outlet between annulars?
6. Is there a booster line?

2.5.4 Operational Considerations

1. Water depth
2. Type of fluid in hole (However, always treat trapped fluid as gas)
3. Diverter system configuration
4. Choke line friction with kill fluid in the choke line and also with water- or mud-based fluid in the line
5. Is the string hung-off?

2.5.5 Removing and Venting Trapped Gas

Gas accumulation

It is most likely that gas will have accumulated under the closed annular or pipe ram (if hung-off) during displacement or removal of the kick.

C&K circulation connection

If a C&K circulation connection is immediately below the annular or ram used for shut-in, this volume will be small (trapped volume 0.5 to 1 bbl) and does not pose a serious threat. Otherwise, a special procedure for removing and venting trapped gas may be necessary prior to opening the BOP to the riser.

General procedure for gas removal and venting

A general procedure for removing and venting trapped gas is shown below.

Check maximum allowable delta pressure from above the BOP

CAUTION: Consult annular manufacturer regarding the maximum allowable delta pressure from above the BOP.

Step	Action
1	Isolate the wellbore from the riser by closing a pipe ram.
2	Circulate hydrate-inhibited seawater (diesel or base fluid as appropriate) across the stack. Hold back pressure to keep BOP pressure from falling below original pressure (prevent premature expansion of trapped gas bubble).
3	After circulation is completed, keep back pressure on the choke line and BOP stack.
4	Close the subsea upper kill line valves.
5	Bleed choke line pressure side to allow gas to expand into the choke line, unloading the displacement fluid through the fully opened choke at the surface. *Note: In many cases, the trapped gas may not fully displace the choke line due to insufficient expansion energy.*
6	Consider sweeping some of the remaining gas down into the choke line by opening the annular and letting the riser fluid U-tube into the choke line. *Note: Choke line friction will limit U-tube velocity and impair the effectiveness of the sweep.*
7	Close annular and displace the C&K lines and stack with kill weight mud. Pump down the kill line side.
8	Open the annular and circulate kill weight mud in stages, removing any remaining trapped gas from riser.
9	Check pressure under closed ram. Open rams and continue operations.

Table 2- 12 Removing and venting trapped gas.

2.6 Gas in Riser: Riser Diverter

2.6.1 Summary

The objective of this subsection is to outline steps that can be taken on deepwater floating drilling vessels, where gas may be present in the riser.

2.6.2 When to Apply Gas in Riser Procedures

- After shutting-in a kick where some of the gas influx gets above the subsea BOP. The potential for this increases with water depth and is also influenced by mud-type, i.e., gas solution in synthetic mud (See Chapter 2.1, Kick Detection)
- As a result of a BOP leak across ram/annular into riser
- For removal of trapped gas (See Chapter 2.5, Trapped Gas)
- To deal with return air/gas from riser if the riser fill valve opens to refill riser after loss of riser mud

2.6.3 Actions/Considerations in Handling Gas in Riser

CAUTION: Minimize personnel on rig floor to those who need to be there

Monitor the riser during well control operations to assess if any gas is in riser. If gas is present, monitor its expansion progress.

Ensure that BOPs are not leaking

If gas in riser or riser flow is detected, ensure that BOPs are not leaking. Close a second BOP above the first one and bleed/monitor pressure between the BOPs.

If flow is detected, estimates of its development into rapid expansion, high flow rates, and resulting surface pressure are not reliable. Such development can occur quickly.

Prior to gas arrival:
- **Line up equipment and personnel**
- **Verify capacity of mud/gas separator assigned to riser**
- **Divert riser return flow overboard if necessary**

Riser slip joint pressure limitations may be reduced if rig is heaving

Riser gas handler below the slip joint allows backpressure control of flow rate

Therefore it may be desirable to promptly line up equipment and personnel prior to gas arrival, including diverting all riser return flow directly overboard, bypassing the mud/gas separator. This depends on assessed rate and pressure capacity of large-sized mud/gas separator assigned to riser and of riser slip joint.

Be aware of riser slip joint pressure limitations, which can be reduced if rig is heaving. Check manufacturer for rating and determine desired test procedures to assure slip joint integrity.

If rig is equipped with a riser gas handler below the slip joint, it will allow handling of riser gas with a back pressure to control the rate of flow.

2.6.4 Alternatives for Handling Riser Gas

CAUTION: If gas surfaces, it may do so abruptly and at high rate giving little, if any warning

Alternative procedures for handling riser gas are listed below:

Close	Then
Diverter	Monitor the end of the diverter line for evidence of flow.
Diverter	Line up flow to trip tank. Monitor trip tank level for evidence of flow.
Diverter	Line up to dedicated riser mud/gas separator, if provided.

If rig is so equipped:	
Close	**Then**
Special annular below slip joint	Line up flow to assigned manifold.

Table 2- 13 Alternative methods for handling gas in riser.

2.6.4.1 Riser Fill-up Valve Operation

Determine if and where the valve is to be run in the riser. Select automatic and/or manual valve operation settings. If the valve is installed too shallow, riser flow can prevent sea water entry.

Open valve before riser evacuation reaches riser collapse rating.

Open valve before riser evacuation reaches riser collapse rating.

2.6.5 Actions/Considerations in the Timing of Riser Circulation

The following tables compare the options of deferring riser circulation until after the well is killed with riser circulation prior to killing the well.

2.6.5.1 Riser Circulation after Killing Well

Deferred Riser Circulation	Comments
Riser gas migration is not a more difficult problem beyond the need to prepare for gas surfacing	Allowing the gas to migrate increases the degree to which it can disperse, reducing surface handling problems (See 2.5, Trapped Gas)
Simultaneous riser and well killing (or volumetric control) operations split the attention of operations personnel	Can lead to oversight or error
Difficulty in isolating and keeping track of mud volumes from well and riser	
Difficulty in detecting leaking BOP	
There may be equipment limitations against simultaneous operations	
Deferral of well killing operations increases potential for downhole problems	• Hydrate formation • Difficulty in using DP pressure to measure BHP in static, cold system (viscosity, float valve) • Reduces potential benefit of using Wait & Weight method to reduce casing shoe pressures, to the extent that influx migrates up to casing shoe (See 2.3, Circulating to Kill)

Table 2- 14 Deferring riser circulation until after well is killed.

2.6.5.2 Riser Circulation before Killing Well

Use of kill weight mud for circulating riser

If the decision is made to circulate the riser first, use of kill weight mud for this may create an inverted pressure load on the BOP ram or annular in excess of manufacturer recommendation.

Consider if sufficient weighting material is available for downhole mud weight increase.

Advantages to Riser Circulation Prior to Killing Well
• Helps insure that gas does not surface while personnel attention is focused on another operation (well control)
• If gas is determined to be at/near surface, its rapid expansion may demand immediate attention
• If Wait & Weight method of well circulation is going to be used, time may be available to circulate riser while pit mud weight is being raised

Table 2- 15 Riser circulation prior to killing well.

After the well is killed and trapped gas removal procedures are completed, consider the following steps:

After the well is killed and trapped gas removal procedure is complete

1. Circulate the riser over to kill weight mud in 25% increments with 15 minute monitoring periods between increments to detect if any gas is already in the riser.
2. If gas or flow increase is detected, shut down pumps and line up to divert overboard.

2.6.5.3 Closed BOP during Riser Gas Handling

A BOP should be closed during riser gas handling for the following reasons:

Closed BOP for riser gas handling

- If the BOP is left open, gas expansion can underbalance the hole, potentially leading to additional influx if formations are exposed
- A closed BOP isolates the wellbore from riser
- The well can be monitored through a C&K line outlet below the closed BOP
- The riser can be circulated with a riser booster line and/or C&K line with outlet above closed BOP

2.6.5.4 *Riser Circulation Rate and Diverter Flow*

Circulation rate

Circulation rate should depend on the following:

- Size and capacity of diverter/circulation system
- Liquid and gas handling capacity of surface equipment
- If pumping kill weight mud, capacity of mixing system to maintain density

Diverter flow may be directed to mud/gas separator or directly overboard depending on the following:

- Mud type
- Environmental impacts/rules
- Mud/gas separator capacity (riser discharge is likely to peak at a high rate)
- Pre-determined estimated exit rates of gas and liquid that result from various pump rates and riser gas volumes

2.7 Hydrate Prevention/Removal

See also *Well Planning, 1.4, Hydrates*

2.7.1 Potential Hydrate Formation

Taking a gas kick in a non-inhibited water-based drilling mud creates the potential for hydrate formation, which can plug the choke and kill lines. Hydrates can also form behind BOP rams, preventing them from opening.

Gas kick in non-inhibited water based mud creates potential for hydrate formation

The deeper the water, the more likely hydrates are to form because of both decreasing temperature and increasing hydrostatic pressure.

Hydrate equilibrium temperatures:
- **2,000 ft water depth 48 degrees**
- **4,000 ft water depth 61 degrees**

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.

Hydrate formation while circulating is very unlikely

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, as well as the decreased time that gas is in the BOP.

Time factor favors driller's well control method

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 (riser volume not needed at this time).

2.7.2 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.

Salt effects on mud density and hydrate formation temperature

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.

2.7.3 Alternatives to Salt Inhibition

The table below identifies alternative drilling fluid inhibition methods:

Additive/Method	Comments
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, so there may be no gas in the BOP. 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	• After a kick, a glycol pill may be spotted in the BOP stack via the choke and kill lines. • To prevent hydrates, glycol may be pumped down a dedicated glycol injection line from the surface to the BOP, if the rig is equipped with this line.
Methanol	Not a desireable mud additive because of toxicity issues.

Table 2- 16 Alternative hydrate inhibition methods.

2.7.4 Hydrate Removal

Hydrate plugs difficult or impossible to reach with inhibitors or heated fluid

Once hydrates form in subsea equipment, 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 subsea BOP.

Pumping heated fluid down coiled tubing inside drill pipe

In one of the cases where heated fluid was successful, it was pumped down coiled tubing that was 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.

Coiled tubing through C&K line

A special approach involves running a coiled tubing down a C&K line, with a surface lubricator packoff (i.e., access through a mouse hole). This offers two choices:

- circulate and wash glycol to bottom of C&K line
- nitrogen/air lift C&K line to evacuate and reduce hydrostatic pressure to decompose hydrate

2.7.5 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-BOP stack connector. Once formed, these can prevent unlocking of the connector.

Hydrates may form in locking mechanism of wellhead-to-BOP stack 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 BOP stack.

2.7.6 Removing Wellhead Connector Hydrates

Procedure options to remove wellhead connector hydrates are listed below:

Step	Action	Comments
1	Circulate at a maximum rate (e.g., 3 pumps) with the drill pipe in the BOP stack 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 recirculate returns can be determined by wellbore thermal simulation software. • Modeling should include the temperature distribution from the inside of the BOP 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 issues prior to action.*

Table 2- 17 Procedures for removing wellhead connector hydrates.

2.8 Well Control Prior To BOP Installation/Shallow Water Flow

See also *Well Planning, 1.2, Shallow Water Flow Control Guidelines*

2.8.1 Shallow Water Flows

Shallow water flows (SWF), or gas flows, can be a problem when drilling with seawater with returns to mudline before the BOP and riser are installed. While pressurized zones may also be encountered after the BOP is set, the difficulty of dealing with them is less if they can be shut in.

Shallow sand pore pressure

Pore pressure of shallow sands can be as high as 80 to 90% of overburden. Furthermore, gas may be seen with shallow water flows, and is likely solution gas. Higher hydrostatic pressure in deeper water leads to higher solution gas content. In some cases, the flow may even be predominately gas.

SWF rates can be high

Flow rates can range from very low (near levels of detectability) up to several barrels per minute, and often contain significant amounts of sand.

Consequences of SWF

The likely consequences of sustained shallow flow include:

- Hole erosion
- Post cementing annular flow and broaching, crater formation
- Surface subsidence
- Loss of well and/or conductor/template support

Origins of SWF zones

While, permeability of SWF zones can be quite high, on the order of darcies, the origins of overpressured shallow formations are of a geologic nature and include:

- Trapped salt water that is pressured by the overburden loading, which is known as undercompaction.

- Massive turbidite depositions during the last ice age along continental slope. The pore water may be fresh

Delayed SWF reaction
SWF avoidance

SWF may not be noticed at first as the zone may be cased off and cemented. The flow may be a delayed reaction after cement sets and/or may broach to the surface at a considerable distance from the wellbore. Hence, an ROV should be regularly used to monitor both well and the vicinity of the well for evidence of flow.

2.8.2 Approaches to Drilling SWF Zones

The primary control method has been avoidance.

The table below includes several approaches to minimizing the risk of SWF problems:

Approach	Comments
Use shallow seismic surveys and all available offset data to select a location that minimizes shallow sand content.	• Geohazard surveys used to avoid shallow gas (or gas hydrates) can also help select casing setting depths to limit exposure to potential SWF reservoirs in the conductor and surface hole sections.
Drill the hole sections with whole mud	• Large volumes of mud, e.g., 25,000 bbls, pass through the bit once and then flow out on the sea floor. • This technique has provided success in getting 20" conductor casing to 4,000 ft BML.
Allow shallow flows to occur, but monitor their intensity (drilling with seawater). **CAUTION:** If SWF intensity is excessive, the well may have to be abandoned and restarted using another method.□	• If SWF starts, a kill action is initiated with weighted mud. • Subsequent drilling is done with mud (optimum density is a matter of trial and observation).

Table 2- 18 Approaches to drilling SWF zones.

2.8.3 Procedures for Mitigating SWF Problems while Drilling

The following precautions and mitigations are employed in drilling SWF potential hole:

Factor	Comments
Kill weight drilling fluid	• Dynamic and/or weighted fluid kill procedures, including mixed mud, should be ready to implement immediately. • At least two hole volumes of kill mud will be needed. If well is not dead after pumping two hole volumes, further pumping is rarely effective. Change mud density or pump rate. • Adjust kill weight up to maximum if large flow rate is expected. • Add tracers (dye, mica, etc.) to sweeps to help identification in ROV video.
Pump rates	• Kill using maximum pump rate with multiple mud pumps. • It is nearly impossible to pump too fast as annular pressure drop is very low. • Rate is limited by available mud pumps and drilling string internal pressure drop (i.e., drill string ID). • The bit nozzles selected should take into account kill circulation procedure. • Verify that any PWD/LWD equipment has maximum circulation rate capability that is compatible with dynamic kill procedures.
Exposure time: pilot hole	• A small pilot hole (9 7/8" or less) increases the capability of dynamic kill procedures, including pump rate and required mud volume and density. • However, the trend is to simultaneously drill and underream a large hole fast to minimize exposure time and hole enlargement . • In this case, the kill procedure must rely on kill fluid density and high pump rate to minimize mud dilution by the influx flow.
Exposure time: drill/underream	• Minimize exposure time as much as possible to limit hole erosion. • The trend is to simultaneously drill and underream a large hole fast to minimize exposure time and hole enlargement. • In this case, the kill procedure must rely on kill fluid density and high pump rate to minimize mud dilution by the influx flow.
Annular flow rate	• Pump gel sweeps at regular intervals to help quantify annular flow rate by timing returns at seawater at constant circulation rate. • Ultimately, if drill pipe is filled with seawater behind a successful kill, all annular flow should stop.
Trip depth and total depth	• Fill hole with weighted mud to insure pore pressure overbalance and improved wellbore stability. • Maximum weight is set by pressure integrity (overburden pressure) of any previous casing shoe, i.e., structural casing.
U-Tubing	• U-tubing will occur after shutting down pumps. • This helps maintain kill but may indicate continued well flow on ROV video. • Qualitative interpretations of prior videos can help judge that well is dead.

Table 2- 19 Procedures for mitigating SWF while drilling.

2.8.4 Other Procedures and Observations

External casing packers (ECP)

Using an external casing packer to seal the annulus is a technique used by some operators to handle shallow water flows (SWF). This is closed after the cement has been put in place.

PWD and LWD data

Pressure while drilling (PWD) tools have been used to help detect SWFs. However, the interpretation of the data is a problem. Logging while drilling (LWD) resistivity may be used along with PWD in 26" diameter holes but the results are inconclusive and still being investigated. The use of a small pilot hole may improve response of the LWD.

Mud loss after successful kill

Mud loss after a successful kill has been a problem. Sands were drilled underbalanced with no filter cake formation. Overbalance (after a kill) can lead to high seepage losses. Mud losses due to permeability are possible in these un-compacted sands. Use fiber with a varying range of bridging solids to remedy this mud loss.

Cementing

Water flow should be killed with mud prior to cement job. Casing diameter can assist in killing well by providing higher annular velocity and friction for a given pump rate.

Cement channels

Positive solutions to cementing in shallow water flow environments are still in development. Foam cements aid in controlling shallow flows. Uncemented (mud filled) channels are a potential route for continued water flow after cementing. Mud displacement and minimizing cement transition time at low temperatures is a key. Excessive hole erosion can lead to poor mud displacement. The mud chemistry may be altered to facilitate cementing.

If excessive flow is possible that cannot be easily killed or causes large hole erosion, then alternate control methods should be considered.

2.9 Plug and Abandon

2.9.1 Summary

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

Deepwater effects on P&A 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 in casing and casing annulus

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 overpressured gas exist below the seal assembly.

2.9.2 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.

Possible pressure buildup due to gas behind casing

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, another approach is to use drill pipe as a lubricator to a distance below the stack, shut-in, then run the perforating gun through and below the drill pipe.

2.9.3 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.

2.9.4 Seal Assembly Removal

When removing the seal assembly, trapped gas can escape, either rapidly if it is overpressured 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 either the drill pipe or a kill line (and up a choke line) to remove any influx and monitor flow. This can minimize the potential for influx gas to get above the BOP and into the riser before being detected.

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.

2.10 Intermittent Severe Weather and Eddy Current Guidelines

2.10.1 Summary

This guideline provides a minimum basis for approaching the numerous and varied issues surrounding intermittent severe weather in normally benign operating areas such as the Gulf of Mexico (GOM). A discussion of certain issues involving eddy currents in the GOM is also included.

This guideline does not include all of the monitoring and preparations that will be required in all operating instances. Rather, the guideline is meant to provide a basis from which a complete severe weather and eddy current contingency program could be built.

2.10.2 Monitoring and Tracking

Monitoring of the weather and currents at and around the deepwater drilling location should commence as early as possible in the well planning phase. Historical met-ocean data and daily updates with weekly (and longer) forecasts are available from numerous commercial sources including:

- Ocean Routes
- Storm Data

Public information is available from the following sources:

- National Weather Service
- University Of Colorado, Boulder, Center For Remote Sensing and Image Processing

Eddy Watch Group

Historical and actual eddy current data are available from the Horizon Marine-operated Eddy Watch group. This data can provide the basis for contingency planning, as well as a guide to the likely occurrence of a high current event at a particular deepwater drilling location.

2.10.3 Intermittent Severe Weather Response

Example operating system

In general, most severe weather response systems are comprised of a multi-phased response and evacuation program. The following is an example of an actual operating system used in the GOM for a dynamically positioned drillship.

Alert zones

2.10.3.1 Yellow Alert Zone

General geographic area around the operating location, i.e., the entire Gulf of Mexico.

2.10.3.2 Red Alert Zone

Extends radially from the MODU to a distance such that the projected time to secure and evacuate equals the estimated time of arrival of the hurricane.

2.10.3.3 Arrival Time

Arrival time

The arrival time of the storm/hurricane is defined as the time of arrival of weather conditions that would make final evacuation of personnel from the MODU by helicopter unsafe. For a DP vessel, the time of arrival of the hurricane would be the arrival of conditions that would stop preparations for disconnecting and evading the storm.

The phases of preparation and response are as follows:

Phase 1: Preparations will be in place and formal monitoring will commence and run from the start of the traditional hurricane season June 1 through November 1.

Phase 2: Severe Weather Warning - Declared when a named storm forms or enters the Gulf of Mexico or the Caribbean Sea.

Phase 3: Hurricane Alert – Declared when a hurricane or storm of hurricane potential approaches or develops within the Red Zone Time + 24 hours of the location.

Phase 4: Secure/Evacuate – Declared when a hurricane or storm of hurricane potential approaches within the calculated Red Alert Zone or within 24 hours of the operating location.

- Start Early Evacuations
- Secure and Evacuate

Phase 5: Return to Work – Declared upon passage of the hurricane.

Yellow Alert encompasses entire GOM

Because of the speed at which a hurricane may travel through the Gulf of Mexico, the radius of the Yellow Alert Zone encompasses the entire Gulf of Mexico. The Yellow Alert Zone coincides with Phase 2.

Whenever a hurricane/storm is in the Yellow Alert Zone, the OIM or Person-in-Charge will calculate the radius of the Red Alert Zone. The Red Alert Zone will be recalculated each time a new weather report is received and/or when an operational change takes place (ie., changing from drilling to running casing).

Calculating the Red Alert Zone

The calculation is made by computing the time required to accomplish each operation to secure and move or evacuate the rig. These times are summed, and the total time is then multiplied by the speed the hurricane is traveling to yield the radius of the Red Alert Zone.

Phase 4 of the Hurricane Evacuation Plan (HEP) is declared by the Person-in-Charge as soon as the hurricane reaches the perimeter.

2.10.3.4 Example Red Alert Zone

Operations dictate that 36 hours are required to secure and prepare to move. The hurricane is traveling 10 NM/hour.

The Red Alert Zone would then extend radially 360 NM from the MODU.

The Red Alert Zone coincides with Phases 3 and 4 of the HEP. Example calculation sheets that may be used to compute the time required to secure and move the MODU are included at the end of this subsection. The calculation sheets are currently in use on dynamically positioned and moored vessels working in the deepwater areas of the GOM.

2.10.4 Loop and Eddy Currents

Loop and eddy currents ranging up to 4 knots are frequently encountered in the deep water drilling areas of the GOM. Associated problems with these events include:

- vessel station keeping
- difficulty in running and retrieving the riser and BOP
- unsafe loads on risers due to rig offset and excessive lower flex joint angles
- potential riser failure due to stress from vortex induced vibration

Industry practice to date has been to avoid operating in areas affected by these events or to move from the area when loop currents or eddy currents are detected nearby.

Individual vessel limitations generally govern operating windows for high current operations. A vessel designed to operate in 2 knots surface current may be able to continue operating in currents up to that level. However, the effects of the current on the marine riser may dramatically change a vessel's operating capability with very long risers and heavy mud weights.

In general, practices used for severe weather response planning can be applied for high current event contingencies. However, while the generally accepted technique for dealing with hurricanes is to move the vessel out of the path of the storm or evacuate, one major issue

involving a current event is the decision to remain latched up or disconnect.

Detailed riser analysis

To address this issue, a detailed riser analysis is recommended prior to commencing any deepwater operations. One objective of the analysis is to identify what approaching current conditions would require the well to be secured and the riser pulled.

Additionally, disconnect criteria should be established such that the operations personnel clearly understand under what conditions the riser should, and should not, be disconnected.

Disconnect decision matrix

A disconnect decision matrix would be one approach to assist operations personnel in their understanding of the numerous and varied issues surrounding the disconnect decision and the establishment of the disconnect criteria. The matrix development would include consideration of the following well, vessel, riser, weather and current issues:

1. Well phase criticality - depth, horizons open, mud weight, open perforations.
2. Vessel station keeping capabilities and the influence of the riser in both the connected and disconnected state.
3. Flex joint angle(s) monitoring and capability.
4. Riser tensioning capability.
5. High current riser retrieving capability.
6. Weather and current conditions and forecast.
7. Wellhead, casing and possible subsea tree strength and / weak points.
8. Under what combinations of weather and current loading is a disconnect acceptable.
9. A clear understanding of the roles of all parties who will make the decision to remain connected or disconnect.
10. How the decision will be made, communicated and documented.

The establishment of a clear and workable disconnect decision process is fundamental to the success of any response program.

2.10.5 Riser Margin

Normal operating practices (and in many areas, government regulation) have traditionally required a mud weight in excess of the formation pressure such that, in the event of an emergency disconnect, the mud weight remaining in the hole will balance the formation pressure of the well.

Riser margin

This added mud weight is to compensate for the loss of hydrostatic pressure of the mud column from the wellhead back to the rig when the BOPs are closed and the riser is disconnected.

Hydrostatic pressure lost in the well following the disconnect can be approximated as follows:

EQUATION: lost hydrostatic pressure following disconnect

Lost hydrostatic pressure =
(MW - 8.3)*(WD in ft)*(0.052)

In deepwater drilling, where the difference between formation and fracture pressures can be very small, the practicality of this approach becomes difficult as formation pressures exceed a saltwater gradient. For this reason, enhanced well monitoring and training in well control and re-establishment methods is essential.

2.10.6 Alternate Location Contingencies

It is recommended that any operator planning to drill through the loop current season should have an alternative work location ready for the rig prior to the startup of a deepwater campaign. Ideally, the alternative location would be several hundred miles from the primary location, as these types of events tend to affect large areas of the GOM when they occur.

Eddy and loop current events generally tend to be of longer duration than hurricanes, affecting drilling locations for up to several weeks. For these reasons the risk mitigation of having an alternative location available during the loop current season can pay significant dividends.

As the alternative location may involve other operating groups and different operators, it may be necessary to conclude arrangements for this contingency well in advance of taking a deepwater rig on hire.

Hurricane related delays tend to affect large enough areas of the GOM that it may not be practical to choose an alternative location that will not be influenced by the storm. Also, hurricane related delays tend to be of relatively shorter-term duration as compared to multi-week eddy current delays.

2.10.7 Phase 4/Red Alert Calculation Sheet (DP MODU)

Today's Date: _____

Present Operation: _____ Well Depth: _____

Last Casing: _____

Water Depth: _____

Note: Enter N/A for Non-Applicable Procedures.

1.	Secure well per operator's orders.	Time Req'd.: _____
2.	Pull up into casing, L/D drill pipe.	Time Req'd.: _____
3.	Pull Water Depth of Drill Pipe. P/U hang-off tool and RIH.	Time Req'd.: _____
4.	Land hang-off tool and release, pick up and secure well (BOP). Displace riser with seawater.	Time Req'd.: _____
5.	POOH L/D water depth of drill pipe.	Time Req'd.: _____
6.	Evacuate non-essential personnel.	Time Req'd.: _____
7.	Disconnect LMRP, pull and L/D the slip jt and riser. Secure Floor.	Time Req'd.: _____
8.	Back load surplus riser and transfer liquid mud to workboat.	Time Req'd.: _____
9.	Reduce variable load as required.	Time Req'd.: _____
10.	Secure decks; close watertight vents, compartments and doors.	Time Req'd.: _____
11.	Take evasive action, sail vessel out of immediate danger zone.	Time Req'd.: _____

TOTAL TIME TO SECURE WELL AND PREPARE VESSEL TO MOVE: _____

2.10.8 Phase 4/Red Alert Calculation Sheet (Moored MODU)

Today's Date _____

Present Operation _____ Well Depth _____

_____ Last Casing: _____

_____ Water Depth: _____

Note: Enter N/A for Non-Applicable Procedures.

1.	Secure well per operator's orders.	Time Req'd: _____
2.	Pull up into casing L/D drill pipe.	Time Req'd: _____
3.	Pull water depth of drill pipe. P/U hang off tool and RIH	Time Req'd: _____
4.	Land hang off tool and release, pick up and secure well (BOP). Displace riser with seawater.	Time Req'd: _____
5.	POOH L/D water depth of drill pipe.	Time Req'd: _____
6.	Evacuate non-essential personnel.	Time Req'd: _____
7.	Disconnect LMRP, pull and L/D the slip jt and riser.	Time Req'd: _____
8.	Pull up guidelines and slack off mooring wires. Deballast to survival draft.	Time Req'd: _____
9.	Reduce variable load as required.	Time Req'd: _____
10.	Secure decks' secure ballast pump rooms. Secure ballast control room. Close watertight vents, compartments, and doors.	Time Req'd: _____
11.	Evacuate all personnel from MODU.	Time Req'd: _____

TOTAL TIME TO SECURE WELL AND PREPARE VESSEL TO MOVE: _____

2.11 DP Emergency Disconnect Considerations

2.11.1 Summary

During drilling operations conducted in a dynamically positioned (DP) mode, the ultimate goal is to maintain control of the well with no damage to drilling equipment in the event of a station keeping failure.

To prevent damage in the event of station keeping failure:
- **Secure well**
- **Disconnect riser**

Modern DP systems have greatly enhanced the reliability of DP systems for drilling, but incidents still occur. When an incident does occur, it is required that the well be secured and the riser be disconnected before any damage occurs to either the wellhead or any of the drilling equipment including BOP stack, lower marine riser package (LMRP), slip joint, moonpool or riser tensioners.

Loss of station keeping while drilling or tripping

During actual drilling or tripping drill pipe, if there is loss of station keeping ability it is necessary to be able to do the following:

1. Hang-off the drill pipe on pipe rams
2. Shear the drill pipe
3. Effect seal on the wellbore
4. Disconnect the LMRP
5. Clear the BOP with the LMRP
6. Dissipate any energy in the riser/riser tensioning system
7. Safely capture the riser

The timing of these operations is critical, particularly items 1-4 from the above list.

2.11.2 Modeling to Predict Excursions

Modeling analysis can be done to predict various excursion scenarios that could possibly occur. These models can predict excursions of the vessel for various combinations of

environment (for drift off or power loss scenarios) and uncontrollable thrust excursions (or drive offs)

Modeling reaction of rig equipment

It is also possible to model the reaction of rig equipment during these excursions. The items that are critical during an excursion are as follows:

1. The LMRP connector/lower flex joint angle
2. Moon pool clearance
3. Slip joint stroke
4. Tensioner stroke limits

Timing of disconnecting the LMRP is critical to prevent risk of bending/damaging wellhead and /or riser

It is critical to have the LMRP disconnected before either the LMRP connector reaches its limits for disconnect (~10°) or the slip joint strokes out or contacts the moonpool. Otherwise, there is a high risk of bending/damaging the wellhead or losing the riser, or both.

Once the disconnect sequence is initiated there will be a finite interval of time before the disconnect actually takes place. Therefore, it is necessary to initiate the disconnect well before limits of any of the equipment are reached.

The final disconnect sequence should be initiated at least 30-40 seconds prior to limits of any equipment being reached

On most drilling units in use today, systems are designed so that once the final disconnect sequence is initiated with all required subsea functions taking place in sequence automatically, the LMRP will lift off in 30-40 seconds. Therefore the sequence would be initiated at least 30-40 seconds prior to limits of any equipment being reached. In reality, it is best to begin this sequence earlier in the event of any malfunctions or miscalculations.

Clearly define point at which to initiate disconnect as driller may have to make a fast decision independently

The point at which to initiate the disconnect must be clearly defined with no ambiguities, since the driller alone may have to make this decision quickly with no help from a toolpusher or company drilling supervisor. The following questions must be answered well in advance of an event:

- When should preparations to disconnect begin?
- What is the best indicator to use?

If a certain pre-defined limit is reached, then the sequence must be initiated. (It is explicit that there will always be communication with the DPO and driller.)

2.11.3 Watch Circle

Traditionally in DP operations, many people have used offset distance, measured in percent of water depth, to establish "watch circles" to indicate when to begin disconnect procedures.

Simplified example: Preparation for a disconnect begins at a distance of 2.5% of water depth, with disconnect initiated at 5.5% water depth

To oversimplify some of these procedures, preparation for disconnect would begin at a distance of 2.5% of water depth, and disconnect initiated at 5.5% of water depth. Generally, an offset of 2.5% constituted a "yellow alert" and an offset of 5.5% of water depth constituted a "red alert".

It is assumed that there will be time to safely disconnect and clear the LMRP before any equipment reaches its limits. With low mud weights, this is probably true except for the most extreme conditions.

Effects of mud weight on lower flex joint angle limits

With higher mud weights, however, lower flex joint angle will be much higher than for lower mud weights for the same given offset. Additionally, the lower flex joint angle, particularly at higher mud weights, reaches its limit of 10° before the other items reach their limits. At the lower mud weights, the lower flex joint angle reaches its limit at about the same time as the other items.

Real time flex joint angle readout is usually available at the DP console

On most modern DP rigs, equipped with a multiplex control system, flex joint angle read out is available at the DP console on a real time basis, and can be tied into an alarm on the drill floor. For this reason, some rigs use the lower flex joint angle instead of offset as the primary indicator of the time disconnect. Offset is certainly a part of the equation, but is used for information rather than the definitive indicator.

Tying flex joint angle readings into alarms on the rig floor allows for an independent alarm over and above direct communications with the dynamic positioning operator (DPO).

Flex joint readings on rigs in de-graded status

On rigs in a de-graded status, a reading of flex joint 3° would indicate to the driller to hang off drill pipe and prepare to disconnect ("yellow alert" status). A reading of flex joint 5° would indicate that point which to disconnect ("red alert").

Except for the most extreme conditions, if a disconnect is effected at a lower flex joint of 5° and if the LMRP lifts off in 30-40 seconds, all equipment should remain within its operating limits. While communications with the DPO are crucial, the driller's access to a direct read out is a redundancy in the event communication with the DP room is lost for any reason.

In deepwater, slip joint stroke may become limiting factor rather than lower flex joint

As rigs move into deeper water, slip joint stroke could well become the limiting factor rather than lower flex joint, especially at lower mud weights. Since offset increases for a given lower flex joint angle in deepwater, longer slip joints may be a requirement in ultra deepwater .

2.11.4 Establishing Procedures

No matter what criteria is selected for yellow and red alert, these procedures must be short, clear, and concise. There should be no ambiguities.

It is unfair to the driller to require him to make too many judgment calls in the heat of the battle. Situations must be reviewed before operations start so that final procedures are clear:

At a certain limit the pipe is to be sheared and the LMRP disconnected – NO QUESTIONS ASKED.

Procedures should be posted in the driller's house and there should be a clear procedure for each of the following:

- Normal drilling operations
- Well control situations
- Casing across the BOP
- BHA across the BOP

General procedures should require that the toolpusher and company representative be on the floor any time that there is anything in the BOP that can't be sheared.

Multiplex BOP control system

Modern DP MODUs generally are outfitted with a multiplex BOP control system. This is a requirement due to the speed of response required to disconnect. Additionally, sufficient hydraulic storage should be available on the BOP/LMRP to allow for the disconnect sequence to function with no recharge from the surface.

2.11.5 Levels of Vulnerability

Clearly, whenever the riser is connected, vulnerability is high for a severe incident. Following is an estimation of increasing levels of vulnerability with a brief discussion of each.

2.11.5.1 Bit above BOP Stack

This is the point of least vulnerability, and is the preferred position for any operation other than being on bottom drilling.

2.11.5.2 Drill Pipe across Stack

Drill pipe across stack; May be necessary to hang-off DP, shear and disconnect

Whenever drill pipe is across the stack, the driller must always be cognizant that it could become necessary at any time to hang-off the drill pipe, shear and disconnect.

Room for block to slack off to keep tool joint at hang-off point

He must also be aware that as the rig drifts off location during a station keeping upset, he will have to leave enough room to allow the block to slack off to keep the tool joint at the hang off point.

Minimize slip time and leave as much pipe as possible hanging

For this reason, slip time should be kept to a minimum, and when drill pipe is hanging from the elevators, as much pipe as possible should be left hanging.

These practices have to be clearly communicated to any one who is on the rig. While experienced DP operations personnel understand these issues, with the wave of new builds/conversions under construction, experienced personnel are in short supply.

Test shear rams to both shear and hold working pressure relative to any drill pipe in use

Shear rams must be tested on the rig to both shear and hold working pressure on any drill pipe that will be across the stack. Some drilling rig BOPs are equipped with dual shear rams to provide redundancy in the event of a disconnect. This is philosophical issue that has to be addressed by both contractor and operator.

2.11.5.3 BHA across Stack

The BHA should be held to a minimum in the likely event that the BOP system is not capable of shearing the components. Heightened levels of alert should be implemented when the BHA is across the stack, with

provisions and procedures for dropping the string in the event that a station keeping upset occurs while the BHA is across the stack

2.11.5.4 Well Kick

Hang-off during well control situations if possible

It is advisable to hang off during well control situations so that in the event of a station keeping incident, activity is kept at a minimum in the event a disconnect is necessary.

Drill pipe float

Running a drill pipe float should be considered as an extra barrier in an attempt to keep pressure off the drill string for reconnect operations. Consideration must also be given to the affects of disconnect with the riser full of mud and the annular closed.

2.11.5.5 Casing across the BOP

This is possibly the most vulnerable situation during DP drilling operations. Only recently have BOPs had the ability to shear casing. In the past, the procedure for handling a station keeping incident while casing was across the BOP called for a procedure where by the casing was dropped.

Risks of dropping casing

This procedure, from a practical standpoint, is clearly fraught with risk. The ability to drop casing in an expeditious manner is suspect, even with air operated tools. Further, the speed at which the casing would fall would seriously jeopardize the ability to close the BOP in time in very deep water.

New BOPs can shear casing, but requires longer than shearing drill pipe

Newer BOPs with the ability to shear casing are much more advantageous. However, procedures must be closely planned and communicated since shearing casing and securing the well for disconnect will most likely take longer than shearing and sealing on drill pipe.

Some casing shear rams do not seal after shearing. Therefore, consideration must be given to placement of these rams in the event of having stuck casing across the

stack and having to disconnect due to station keeping problems.

Even if casing is sheared, if it is stuck across the blind shear rams, there is no way to secure the well for a disconnect.

Long, heavy casing strings:
Any landing string joint across the BOP stack must be capable of being sheared

Another consideration for deepwater DP operations are long, heavy casing strings. Some of these strings will require heavy, high strength landing stings. It is a requirement that whatever landing string joint is across the BOP stack is capable of being sheared. If the landing string cannot be sheared, it is generally possible to substitute a joint of lesser weight pipe on the bottom of the landing string that can be sheared.

2.11.6 Consequences and Costs: Drilling with Riser

It is obvious that the potential costs of a failure to disconnect could be catastrophic with far reaching implications. Potential results of a failure to disconnect include the following:

- Damaged wellhead
- Damaged BOP
- Loss of riser
- Uncontrolled subsea blowouts

It is difficult to quantify the costs of these scenarios. At the very best the costs would be astronomical, with the potential to have legislation suspend DP operations in the area of a disaster.

This suspension could conceivably last years until all questions have been answered and procedures dictated from governing bodies. Costs could be upward of $100 million.

2.11.7 Emergency Disconnect Sequencing (EDS) Considerations

Following are some specific considerations concerning the actual sequencing of the BOP for an EDS:

Condition/Issue:	Recommendation/Comments:
Casing shears are utilized in the BOP stack	Have two modes for the Emergency Disconnect Sequencing (EDS) because if the casing shears do not seal and the casing is not in the hole, valuable time is lost closing the casing shear ram
Time recommended for complete disconnect of packages	• Pipe Mode – should be accomplished within 30 seconds • Casing Mode – should be accomplished within 45 seconds

Table 2- 20 General considerations concerning BOP sequencing for an EDS.

If operations are in the Pipe Mode, implement the following steps:

Pipe Mode Emergency Disconnect Sequencing	
Step 1	• Ensure pod stringers are extended • Close shear ram • Close all choke/kill stack valves • Open riser fill valve if in use • Retract all acoustic stabs • Block all additional ram and annular functions
Step 2	• Unlock riser connector (use both primary and secondary unlock) • Unlock/retract choke and kill stabs if equipped with retractable type stabs • Block all choke/kill stack valves
Step 3	• Block shear rams • Retract pod/stingers
Note: At this point, consideration should be given to opening the annular to release mud in the riser if riser analysis indicates that the riser could be damaged in high seas with heavy mud in the riser.	

Table 2- 21 Pipe Mode emergency disconnect sequencing

If operations are in the Casing Mode, implement the following steps:

Casing Mode Emergency Disconnect Sequencing	
Step 1	• Ensure pod stringers are extended • Close casing shears • Close all choke/kill stack valves • Retract all acoustic stabs • Block all additional ram and annular functions
Step 2	• Close shear rams • Block casing shears • Open riser fill valve
Step 3	• Unlock riser connector (use both primary and secondary) • Unlock/retract choke/kill stabs • Block all choke/kill stack valves
Step 4	• Block shear rams • Retract pods/stingers
Note: At this point, consideration should be given to opening the annular to release mud in the riser if riser analysis indicates that the riser could be damaged in high seas with heavy mud in the riser.	

Table 2- 22 Casing Mode emergency disconnect sequencing

Sequencing of steps can vary based on the manufacture of the stack components and the manufacturer's published information on closing time requirements.

Volume requirements and actual functioning times should be used for disconnect sequence design

When designing the disconnect sequence, the volume requirements and actual functioning time of each individual function actuated needs to be examined so that the timing desired can be obtained.

Casing shear volume requirements

Particular attention needs to be paid to casing shear volume requirements if they are a part of the disconnect sequence. Strong consideration should be given to modeling the system to determine if enough fluid under suitable pressure will be available during the disconnect sequence.

Pilot volumes, ability to maintain pilot pressure to SPM valves

Factors that should be examined in addition to fluid volumes to required to activate functions include pilot volumes required and the ability to maintain pilot pressure to the SPM valves during the disconnect sequence.

2.12 Unplanned Disconnects: Prevention Measures and Emergency Response

2.12.1 Introduction

Early in 2000 two unplanned disconnects on two different rigs took place within a matter of weeks. In each case the cause was human error. Though similar cases have not taken place in memory, the events were cause for concern. In an initial investigation MMS required installation of more positive latches or covers for the LMRP disconnect function on BOP control panels. In addition to the immediate response MMS requested industry to reconvene the IADC Deepwater Well Control Task Force to study the problem and investigate both short and longer term preventative and emergency response measures.

In each case the cause was human error

Throughout April and May 2000, industry representatives from contractors, operators and service companies investigated a range of options. Reporting the options and recommendations ensuing from the work done by subcommittees is the subject of this report.

2.12.2 Executive Summary

The focus of this study is on measures for prevention of unplanned disconnects that will reduce the risk of such an event to a level as low as reasonably practicable.

Mechanical, software, operational and training practices are recommended as barriers to prevent anyone from executing an unplanned disconnect without bypassing one or more barriers

Mechanical, software, operational and training practices are recommended as barriers to prevent anyone from executing an unplanned disconnect without one or more barriers being bypassed. Measures to ameliorate the consequences of an unplanned disconnect have been evaluated as a secondary level of assurance to prevent flows from the well if somehow barriers to unlatch the LMRP are breached.

The considered recommendation of the committee is that all practical preventative measures be applied to floating rig operations in the OCS at a deliberate pace and that one or

more of the mitigating measures may be applied as determined most appropriate by the Operator. Some form of emergency closure should be part of any deepwater, dynamically positioned rig BOP operating system to allow closure of the well in the event of the need to disconnect or failure of the control system.

None of the secondary systems evaluated will reliably promote the Blowout Preventer system to a "Blowout Stopper" system. Capping a flowing well will still require measures such as dynamic kill from a relief well. For this reason the focus is on prevention of events such as an unplanned disconnect.

The focus is on *prevention* of an unplanned disconnect

For DP rigs it is important to continue to allow emergency disconnect systems to remain functional. A drive off or drift off without closure of the well and emergency disconnect from the LMRP could cause failure of the riser or well head, both events are more serious than an orderly emergency disconnect. As rigs are moored in deeper water emergency disconnect systems are similarly important to consider for non-dynamically positioned drilling rigs. We have not recommended any measures that will impair the function of emergency disconnect systems.

The study is in two parts addressing prevention and mitigation of the consequences of an unplanned disconnect. First, is a study of means available to prevent unplanned disconnects and second are three separate studies of means available to secure the well after an unplanned disconnect. Use of preventative measures applicable to specific types of rig BOP systems should reduce the likelihood of an unplanned disconnect to as low as reasonably practicable. Incorporation of the mitigation practices should further reduce the possibility of an unplanned release of fluids from the well.

Preventative measures evaluated provide alternatives for all types of systems on both new and older rigs in the fleet without compromise to the goal of avoiding an unplanned disconnect. We do not see any reason that sufficient means to reduce the probability of an unplanned disconnect cannot

be applied to all rigs in the current fleet within a reasonable time.

Securing the well:
1. **ROV Intervention**
2. **Deadman/Autoshear systems**
3. **Acoustic control systems**

The three means for securing the well are: ROV intervention, deadman/autoshear systems and acoustic control systems. Again, all rigs in the current fleet should be able to apply at least one of the mitigation means to their operation in a reasonable time. Each of the alternatives has strengths and weaknesses; these are presented in the comparative evaluation below. Of the three systems evaluated, ROV intervention appears the most simple to apply and most deliberate means to secure the well in an emergency. The Deadman/Autoshear system is a close second. Under normal conditions the acoustic control system should work satisfactorily. However, there have been reliability problems and operating experience with the latest generation of acoustic systems has not yet established a favorable track record of reliability.

Detailed appendices for reports from each of five subcommittees (Prevention and Interlock are combined) are provided in this document and the salient findings have been reduced to two tables with pros and cons of the many options considered.

2.12.3 Recommendations

- Industry should pursue implementation of the Prevention Improvement Measures described on the following page at a deliberate pace.
- One of the Mitigation Systems described on the following page may be provided, as determined most appropriate by the Operator of the proposed well. Other suitable alternatives may be developed by new technology.

2.12.4 Ranking of Alternatives

Alternative	Measures	Pros	Cons
Prevention Improvement Measures	Implement all "Practical" Preventative measures.	+ Comprehensively addresses prevention, which, based on experience, is the problem. + If fully effective, no additional mitigation systems needed.	• Does not address scenarios which somehow get past preventions (sabotage, mechanical or software failure)
Mitigation System Options Implement "Practical" measures appropriate to the Mitigation System selected	1. Provide ROV back-up system	+ Readily applicable to all rigs + Higher level of mitigation protection + Addresses all LMRP and Riser Failure scenarios	• Potential high cost impact for wells that do not already employ ROV and on-board crew. • Time delay to close BOP after incident
	2. Provide Autoshear back-up system	+ Applicable to all types of BOP control systems + Immediate response to incident	• Requires subsea accumulator capacity on lower BOP stack • Does not protect against riser failure
	3. Provide Acoustic back-up system	+ Independent System	• Actuation signal may blocked by well flow, especially if high rate. • Requires subsea accumulator capacity

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2.12.5 Assessment of Options

I. Prevention Improvement Measures			
Option	**Positives**	**Negatives**	**Conclusion**
1. All control panels to incorporate enable buttons to ensure two handed operation for critical functions (LMRP, Well Head connector and Blind Shear Rams	Requires closing to be a deliberate act	May require changes to some existing panels	PRACTICAL
2. Clearly label all functions on all panels	Greater clarity in operation	• Some panels may be congested and not permit large labels • Congestion of panels may make the function the label refers to unclear	PRACTICAL Label the button if panel is congested
3. Color LRMP and Well Head connectors and covers for these functions uniquely	Uniformly indicates critical functions	None	PRACTICAL
4. Fit LMRP and Well Head Connector functions with securable protective covers. • Use Velcro strips, cam locks, lockdown screws, key locks or magnetic latches.	• Prevents accidentally hitting the function button • Requires a pause by the operator to function the button	None	PRACTICAL If used, lockdown screws need to be corrosion resistant and have a capture feature.
6. Disarm function for non-emergency operation of the LMRP or Well Head Connectors (see Item 4 above)	• Lock out of the individual functions • Still permits function of disconnect for emergency disconnect via the emergency disconnect sequence	Additional complication in construction and operation	OPTIONAL Complexity may affect hydraulic system reliability

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I. Prevention Improvement Measures			
Option	**Positives**	**Negatives**	**Conclusion**
6. Disarm function for non-emergency operation of the LMRP or Well Head Connectors for Touch Screen Systems (see Item 4 above)	• Lock out of the individual functions • Still permits function of disconnect for emergency disconnect via the emergency disconnect sequence	Additional complication in construction and operation	OPTIONAL
7. Electronic systems to provide logic warning the operator he is about to initiate a critical command such as LMRP or Well Head Disconnect or Shear Ram function	A second barrier to unintentional function of critical operations	Adds time to execute what could be emergency operations	PRACTICAL for MUX/EH systems. Not applicable for hydraulic systems.
8. Equip Emergency Disconnect System functions with a secured cover and enable button	Safeguard against unintentional function	Adds time to the operating sequence	PRACTICAL
9. On hydraulic control manifold provide the following for LMRP and Well Head Disconnect and Shear rams: • Distinctive "look and feel" compared to other functions • Mechanical barriers such as latchable covers		None – these functions are not primary controls	PRACTICAL
10. For Hydraulic Hose Reels • Post warning signs on hose reels to discourage tampering • Ensure that hydraulic supply isolation valves are "Off" and "Vented" • Remove handles from valves or provide lock-out/tag-out when BOP stack is functional	Prevents unnecessary operation that could lead to unplanned functioning of BOP controls	None, there is no good reason to perform any operation at the Hydraulic Hose Reel when BOP is functional	PRACTICAL

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1. Prevention Improvement Measures			
Option	**Positives**	**Negatives**	**Conclusion**
11. Add interlock prevention devices to prevent functioning the LMRP without first commanding the well by closing a set of blind shear rams	Would prevent unlatching without first commanding the well by closing a preventer	For both MUX and hydraulic systems: • Must be specifically designed for rig they are applied to • Too restrictive • Adds complexity	OPTIONAL
12. Designate in management systems: • Individuals authorized to perform critical functions and maintenance • Include maintenance of BOP equipment in Safety Lockout / Permit to work system	• Requires specific training and awareness of consequences for people performing critical tasks • Requires risk evaluation before working on or around critical equipment	None	OPTIONAL
13. Establish minimum requirements for personnel authorized to operate critical BOP equipment: • Training in well control theory and practice • Comprehensive knowledge of BOP hardware and control systems	• Enhances knowledge of cause and effect for critical functions • Heightens awareness of consequences of operations involving critical functions • Provides a hold point before maintenance on or around critical functions	None	PRACTICAL
14. Perform maintenance on control panel only when the panel is de-energized	Avoids accidental function	None	PRACTICAL
15. Generate and use written procedures/checklists for unlatch of the LMRP or Well Head connector and post near the Hydraulic Control Manifold and Control Panels	• Identifies steps necessary for safe disconnect • Prevents unlatching from an unsecured well	None	PRACTICAL

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E. Prevention Improvement Measures			
Option	**Positives**	**Negatives**	**Conclusion**
16. Riser margin may prevent flow of the well due to underbalance if LMRP or Well Head Connector are disconnected	Positive secondary barrier to prevent well flow	• Not practical in deep water operations • A requirement for riser margin would effectively end drilling activity in many areas • Inability to know formation pressure while drilling makes achievement judgmental and very unreliable.	NOT PRACTICAL as a standard.

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Mitigation System 1: ROV Backup System			
Option	**Positives**	**Negatives**	**Conclusion**
1. Provide ROV function at the BOP for the following: a. 1 set of blind shear rams – closing function b. 1 set of sealing BOPs (drill pipe or second blind /shear ram) – closing function c. ram locks if necessary for the above rams	Provides a positive second means to secure the well in the event of control system failure or unplanned disconnect	• ROV may not be able to access well head due to turbulence in the event of substantial flow from the well • Function time may be slow because of ROV pump rate • ROV may not be in the water • Rig may not be close enough to location for ROV access	PRACTICAL to equip rig with the following minimum ROV access: • Blind shear • Ram lock(s)
2. Contractor to supply ROV hot stab tool that is correct for ROV Intervention panel installed on the rig	Many types of hot stab tools in use, provides assurance correct stab will be available		PRACTICAL
3. Demonstrated ROV capability	Assures adequate closure capability	None	PRACTICAL
4. Demonstrated availability of trained ROV crews with hands on training with stab devices for rig being serviced should be available on board.	Provides some assurance stab and closure can be accomplished in a reasonable time		PRACTICAL There may be more cost effective backup system if ROV crews are not on-board for other reasons.

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Mitigation System 2: Autoshear and Deadman Back-up Systems			
Option	**Positives**	**Negatives**	**Conclusion**
1. Install autoshear device to secure well following unplanned LMRP disconnect	• Automatically shears pipe and secures well • Senses and activates on separation of the LMRP	• Won't activate if riser parts • Requires subsea mounted accumulators on BOP stack with sufficient capacity to power functions controlled • Requires additional BOP control functions to be available (arm, disarm, charge, vent)	PRACTICAL Viable system if subsea accumulator capacity and control system are available or can be provided.
2. Install a deadman system to secure well following riser failure	• Senses loss of hydraulic and/or electric signals from surface and initiates sequence to secure well • Can be manually triggered if desired	• May not be able to handle inadvertent LMRP disconnect • Requires available subsea accumulator capacity to power functions controlled • Equipment not available for conventional hydraulic systems • Potential for false interpretation of riser parting – disrupted signals could be caused by some other event	Optional system for MUX/EH systems; not available for hydraulic systems. • Need for backup system for riser failure is not clear. • May not be effective as backup to unplanned disconnect of LMRP.

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Mitigation System 3: Acoustic Back-up Controls			
Option	**Positives**	**Negatives**	**Conclusion**
Install acoustic BOP controls for critical functions on the BOP stack	• Independent system • Selectable control • Rapid response	• May not work in presence of gas • External noise may affect operability (e.g., sea state effects on thrusters and rig noise, mud flow, well noise, gas bubbles) • Requires independent subsea accumulators on BOP stack with sufficient capacity to power functions controlled • Operation could be blocked by mud flow • Complex • Inconclusive reliability record	OPTIONAL • Viable system if operating data is introduced and there is sufficient space to install bottles • Operating experience has not supported a high level of confidence in the acoustic system in deep water; however, under normal conditions several systems have operated successfully • Operating track records for new systems need to be published • Operation could be blocked by signal attenuation due to water depth.

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Conduct of the Investigations

On March 22, 2000, an organizational meeting was held. In that meeting five areas were identified for study and a list of people to recruit for the project was generated. Members of the Deep Water Well Control Steering Committee and other interested parties then recruited chairpersons for each of the five areas of the study and offered them a list of candidates to serve on the various subcommittees.

Five areas were identified for study

An aggressive timetable with the following milestones was agreed, and a clear definition of the objectives for the study was generated.

IADC agreed to establish a web site for meeting minutes, discussion groups and archive of the various reports to be generated.

Any interested party within the industry was encouraged to participate in the project. Subcommittees, through contacts, drew upon specialty support from controls and BOP manufacturers, ROV contractors and acoustic control suppliers.

Attached is a list of companies that participated in the study and their representatives.

Subcommittee Reports

Final reports from the four subcommittees are provided on the following pages.

2.12.6 Prevention of Unintentional Marine Drilling Riser Disconnect Events

If the marine riser is unintentionally unlatched, the consequences can be very serious. The majority of deepwater well designs are not capable of compensating for the loss of hydrostatic pressure (riser margin) that occurs when the riser is unlatched. In an effort to prevent the riser from being unintentionally unlatched from the BOP stack, the factors that affect or have a bearing on this event have been reviewed. The focus of the Prevention Sub-Committee has been to determine what modifications to existing BOP control systems and/or what procedural revisions may be required in order to prevent marine risers from being unintentionally unlatched.

Most deepwater well designs cannot compensate for loss of riser margin

2.12.6.1 Subsea BOP Control Systems

The components in a subsea BOP stack (i.e., ram BOPs, annular BOPs, choke / kill valves and connectors) are all designed to be operated by use of hydraulics. The ultimate requirement of a subsea BOP control system is to provide the power fluid to perform discrete functions.

The two system designs differ in how signal transmissions, initiated by rig personnel at surface, are sent to control subsea components on the BOP stack

There are two design types of hydraulic control systems for remote operation of subsea BOP stacks. The major difference between the two system designs is how the signal transmissions, initiated by rig personnel, (operating control stations from the rig on surface), are sent to control the subsea components on the BOP stack. The two system variations operate as follows:

A. Hydraulic Control System

By sending hydraulic pilot signals from the surface.

B. Electro-Hydraulic / Multiplex System

By sending electronic/optic signals from surface to an electro-hydraulic (solenoid) manifold subsea which in turn sends hydraulic pilot signals to the subsea manifolds.

Both system design types share **common subsystems.** These common subsystems are:

Common subsystems

- A surface mounted hydraulic pump / reservoir system that is used to provide high pressure power fluid required to control subsea BOP stack components.
- A surface hydraulic accumulator system that is used to store the high pressure power fluid provided by the surface hydraulic pumps.
- A hydraulic control pilot manifold used to direct larger hydraulic valves in the subsea manifold (for hydraulic control systems the pilot manifold is located on surface; for electro-hydraulic / multiplex control systems the pilot manifold is located in the subsea control manifold).
- Surface mounted electric remote control panels used to provide a convenient operational location for the system.
- Umbilical storage reels that provide storage of the umbilical used to connect the surface portions of the system to the subsea portions of the system.
- Subsea control manifold used to control the operation of the well control components in the subsea BOP stack.

The following is a discussion of how the transmission of the command signal differs between these system designs and why one design is selected over the other.

2.12.6.2 Discrete Hydraulic Control Systems

A discrete hydraulic control system has limited water depth capability due to the amount of time required to send a hydraulic pilot signal over a long length of pilot line

A hydraulic control system utilizes a hydraulic pilot signal to transmit operational commands between the surface pilot valve manifold and the larger hydraulic control valves in the subsea manifolds. The hydraulic pilot signals are sent through specialty design hoses that are contained in a multi-core subsea hose bundle umbilical. These pilot hoses are designed to minimize expansion when they are pressurized, thereby reducing the amount of time required to pressure the hose. This reduction in the amount of time required to pressurize the hose assists in the overall amount of time required to function a component on the subsea BOP stack.

The hydraulic control system maintains a low background pressure to pre-expand the control hoses and thus reduce the signal transmission times

Generally, a discrete hydraulic control system has limited water depth capability due to the amount of time required to send a hydraulic pilot signal over a long length of pilot line to operate the various BOP stack components within the time allowed by regulatory bodies. In the past, this type of system was used as the primary design system for most rigs. As the market conditions for these rigs required them to operate in deeper waters, the hydraulic control system has been further enhanced by maintaining a low background pressure to pre-expand the control hoses and thus reduce the signal transmission times. These upgraded hydraulic systems are commonly referred to as **Pressure Biased Control Systems.**

2.12.6.3 Electro-Hydraulic / Multiplex Control Systems

EH / Multiplex systems employ electrically activated, hydraulic valves located on the subsea control manifold

To overcome the water depth limitations of Hydraulic Control Systems, Electro-Hydraulic / Multiplex control systems were developed. These systems employ electrically activated, hydraulic valves (solenoid valves) that are placed on the subsea control manifold. These solenoid valves are used to supply pilot signals to the larger hydraulic control valves in the subsea manifolds. Commands from the surface electric control panels are transmitted via a small diameter electrical / fiber optic cable umbilical to the subsea solenoid valves. This significantly reduces the signal transmission times. Electro-Hydraulic systems transmit signals for a single function over discrete wires in the electrical umbilical. Multiplex systems transmit coded signals for multiple functions over a dedicated wire or fiber optic cable in the umbilical. With the application of these systems, the water depth capability for control of a subsea BOP stack has now been extended to over 10,000 ft.

Commands from surface electric control panels are transmitted via a small diameter electrical / fiber optic cable umbilical to subsea solenoid valves, reducing signal transmission times

Multiplex Control Systems allow greater redundancy (hence reliability) to be built into the system. Incorporation of system diagnostics enhances the ability to troubleshoot the system.

In addition, data logging capability can be included to provide historical data that will show equipment operating trends. The system designer has much greater latitude in

system architecture including the quantity, location and configuration of operating stations.

2.12.6.4 BOP System Control Panels

The unlatching of an LMRP connector should be the result of a deliberate activation based on distinctive appearance and the performance of a required set of operations

The unlatching of an LMRP connector should be the result of a deliberate act by providing this function with:

5. A different appearance (look and feel) to provide immediate recognition and differentiation from other functions.
6. An operational barrier(s) that requires a sequence of operations and/or simultaneous operations to activate.

The above should also apply to the wellhead connector.

Electric control panels (hydraulic and conventional MUX systems) include:

- Driller's Control Panel
- Toolpusher's Control Panel
- Central Control Unit (CCU) - if applicable

Control Panel Considerations

As a minimum, all control stations should incorporate the following:

- An "enable" button(s) is to be incorporated to ensure two-handed operation. It should not be possible to actuate any critical function commanded by the panel pushbuttons unless the enable button(s) is depressed when the function pushbutton is depressed.
- All functions are to be clearly labeled.
- The LMRP Connector (and Wellhead Connector) pushbuttons are to make use of special color backgrounds and/or colored covers.
- The LMRP Connector (and Wellhead Connector) pushbuttons are to be fitted with securable protective covers, requiring deliberate action to access pushbuttons. Acceptable methods of securing these covers include Velcro

strips, lockdown screws, cam locks or other suitable arrangement.

- Other optional alternative measures designed to provide acceptable barriers may also be utilized, such as installation of disarm buttons/switches (with indication) designed to disable the connector release function.

2.12.6.5 Touch Sensitive Screens and Graphic Driven Controls

Control Panel Considerations

- Software is to be provided to lockout discrete functions when not required for routine operation on these systems.
- For critical functions, a warning notice(s) should be displayed advising the operator that he/she is about to initiate a critical command.
- **Warnings for the LMRP Connector (and Wellhead connector) functions should be designed with a different look from other warnings.**
- An "enable" button, either screen based or external to the display, should be provided.
- **The LMRP Connector (and Wellhead Connector) screen mimic pushbuttons are to make use of special color backgrounds.**

2.12.6.6 Emergency Disconnect Sequence (EDS) Functions

All dynamically positioned and some moored rigs are equipped with an emergency disconnect button which triggers a pre-programmed sequence of functions to ensure that the BOP is left in a secure and safe mode upon actuation of the EDS.

EDS function:
- **activated by clearly marked, easily accessible button**
- **equipped with a flip up cover**
- **requires simultaneous actuation of the "enable" button**

Fast actuation of this system is essential to ensure safety of the well and rig. The EDS function should be activated by an easily accessible button that is clearly marked and different from all other control panel functions. It should be equipped with a flip up cover and will require simultaneous actuation of the "enable" button to initiate the sequence.

2.12.6.7 BOP System Hydraulic Manifold

The unlatching of an LMRP connector should be the result of a deliberate act by providing this function with:

1. A different appearance (look and feel) to provide immediate recognition and differentiation from other functions.
2. An operational barrier(s) that requires a sequence of operations and/or simultaneous operations to activate.

The above should also apply to the wellhead connector.

Hydraulic Manifold Considerations

Specifically, for the hydraulic manifold for the discrete hydraulic systems, the suggestions are:

1. The LMRP Connector (and Wellhead Connector) control valve labels should be marked in distinctive colors, conveying caution to the operator. This applies to both primary and secondary unlatch connector controls. The distinctive colors and markings should not be similar to any other functions, such as the shearing blind rams, for example.
2. Other methods to improve recognition may be employed at the discretion of the Contractor / Operator.
3. There should be at least one operational barrier at the manifold, such as opening a protective cover, or installing a manual operation handle. The operational barrier is not intended to make unlocking the connector difficult, only to insure that unlocking the connector is the result of a deliberate act. This operational barrier should not interfere with operation of the function from the remote panels.

2.12.6.8 BOP Control System Hydraulic Hose Reels

Hose Reel Considerations

- Post warning signs on the hose reels.
- Ensure that hydraulic supply isolation valves are "Off" and "Vented".

- Remove the handles from the valves anytime the BOP stack is connected to the wellhead.

2.12.6.9 Control Interlocks

The intent of the interlocks is to prevent inadvertent actuation of the LMRP disconnect. This can easily be achieved with multiplex systems, but may require more complex arrangements on hydraulic control systems.

Interlocks should prevent accidental actuation of LMRP disconnect with MUX systems, but may have issues on hydraulic control systems

This feature has limited experience on MUX systems and no known experience on either EH or hydraulic control systems. Implementation on MUX systems involves a software change. For the systems, implementation involves piping, valves and possibly wiring, resulting in exposure to unintended consequences and failure mode concerns. While these may be addressed through development and experience, it seems inadvisable to undertake implementation on a broad scale at this time. Each system must be considered individually as the interlocks will need to be tailored to a specific rig.

2.12.6.10 Human Factors

Contractors should have management systems which address authority, training and policies / procedures to prevent accidental unlatching of the LMRP (and the Wellhead Connector).

Authority

1. Safety critical operations should be covered by management systems to identify which individuals have the authority to undertake a critical task.
2. The Management System should address what type of notification or approval must be received by an authorized person in order for that person to be allowed to perform maintenance on well control equipment.

Training

The following are minimum requirements for all personnel authorized to operate subsea equipment:

1. Training on and understanding of well control theory and practice.
2. Comprehensive understanding of BOP hardware and control system derived from extensive hands-on training.
3. Training in Hazard Identification to ensure accurate risk assessment.

Policies / Procedures

Any maintenance on control panels should be performed only when the control panel is de-energized and appropriate authorization is obtained, or the BOP stack is on the surface.

A written procedure for unlatching the LMRP connector, during drilling operations, should be prominently posted near the manifold and control panels. This procedure should include steps, checks, time delays, and actions, if required, to both secure the well prior to unlatching and ensure that the equipment will not be damaged.

2.12.7 Securing a Well with ROV Intervention

This section discusses considerations for an ROV intervention to operate a subsea stack function that would secure a well where primary control of the subsea stack has been lost. It should be noted that if an uncontrolled flow is underway through the stack, the chances of being able to fly in close enough to the stack and successfully shut the well in are very low.

An uncontrolled flow greatly reduces ability to shut in the well with ROV

2.12.7.1 Minimum Subsea BOP ROV Intervention Functions

When the need arises to operate specific subsea stack functions using ROV intervention, the following

intervention receptacles should be available to provide the best chance of securing a well and should be considered a minimum requirement:

1. One set of blind/shear rams - closing function
2. One set of sealing rams (drill pipe or second blind /shear ram) - closing function
3. Ram locks if necessary for above rams

The ROV intervention functions should be operationally tested on the rig with a hydraulic pump when stump testing the stack to ensure no operability problems exist before running the stack. This would not require the use of the ROV but could be done with a hydraulic pump using BOP control fluid.

ROV intervention functions should be tested when stack is stump tested

All ROV installations and modifications made on the stack should be analyzed to ensure that they do not interfere with the primary control system and the normal functioning of the stack.

2.12.7.2 Hot Stab/Plug Considerations

Unfortunately, a standard stab/receptacle design was never adopted for ROV intervention on subsea BOP stacks, and as a result many designs are currently used in the field. Two API stab designs do exist -- the 17-D and the 17-H hot stabs -- and they are currently used in the industry. Adopting the API stab designs and working with ROV companies to design and manufacture stabs with the correct material specifications can help ensure a reliable design is used and minimize the number of different designs out in the field in the future. Retrofitting existing BOP stacks to a "standard" design is not practical. As such, the rig contractor should be responsible for being aware of what type of stab is used on their BOP and ensuring they have sufficient spares and blanks (dummies) on board the rig at all times.

Stab/Receptacle designs are not standardized

2.12.7.3 ROV Capability

All ROVs used on floating vessels should be capable of working with a variety of hot stabs and fluid delivery systems. The ROV company should ensure that there are no problems using the rig's stabs and resolve any problems that do exist.

The ROVs ability to be used for stack intervention will be limited by the ROV launching system capability for the given meteorological conditions and sea state at the time the launch is required. Also, if the well is flowing, the ROV's ability to fly up to the stack could be very difficult if not impossible.

Currently, most ROVs have two hydraulic pump capabilities: one high pressure and one low pressure. A typical high-pressure pump operates at 10,000psi and can deliver liquid at 1.5gpm. A typical low-pressure pump operates at 3000psi and can deliver liquid at 4.5gpm. The ROV's pump capabilities must be able to work at the pressures of the stack's control system operating pressure. Also, using the ROV pumps described above, the closing times to operate the rams will be significantly longer than using the stack's accumulator system. If possible and practical one might consider having the option to use the ROV to use the stack's accumulator system to operate the necessary closing functions (this assumes that the bottles remain charged when the ROV attempt is made). Another consideration would be to maximize the pressure and flow rate pump capability of the ROVs onboard hydraulic pumps in order to close the rams as quickly as possible.

The ROV's pump capabilities must be able to work at the pressures of the stack's control system operating pressure

2.12.7.4 ROV Crew Training

If available, simulator training on stabbing into a ROV intervention manifold on a subsea BOP stack should be provided to ROV crews before going to a rig. At a minimum, the ROV crews should practice stabbing dummy plugs into a receptacle on the manifold to become proficient at this practice on the subsea BOP stack (on the rig they are currently working on). If room exists on the

stack, another option would be to set up a dead receptacle on the ROV intervention manifold for a dummy plug which could be used for practice and not jeopardize a live receptacle. Stabbing practice by the ROV operators could be done during riser inspection runs.

2.12.8 Autoshear and Deadman Systems

General Purposes of Autoshear and Deadman Systems

1. To secure the well in case of accidental disconnect of the LMRP.
2. To secure the well in case of a total loss of power/communication and hydraulics to the BOP, which by inference includes separation failure of the marine riser and the associated BOP control lines.

2.12.8.1 Definition of Autoshear System

Autoshear is the defined as the safety feature that automatically shuts in the wellbore upon an unplanned disconnect of the LMRP connector. The Autoshear feature has three status modes: disarmed, armed, and activated. If armed, when the LMRP is separated from the stack, the Autoshear feature activates. Activation closes the shear rams (or other designated BOP). Hydraulic power is obtained from lower BOP stack mounted accumulators. The Autoshear package is typically mechanically activated and uses an independent hydraulic control system.

Autoshear is the safety feature that automatically shuts in the well upon an unplanned disconnect of the LMRP connector

Deadman system automatically shuts in the well if a loss of multiple pre-defined links to the surface occurs

2.12.8.2 Definition of Deadman System – For Multiplex (MUX) and Electro-Hydraulic (EH) BOP Control Systems

A Deadman system automatically shuts in the wellbore in response to a loss of multiple pre-defined links to the surface, as could occur upon parting of the riser. Typically, these defined links are hydraulic pressure, electrical power and/or electrical power. The Deadman system also has three status modes: disarmed, armed, and activated. If armed, the Deadman system activates when the loss of all defined pressures/signals occurs. Activation closes the shear rams and/or other designated BOP and valves.

Hydraulic power is obtained from LMRP and/or BOP stack mounted accumulators. If the Deadman system requires electrical power, a subsea battery is provided.

2.12.8.3 Definition of Deadman Package – For Hydraulic BOP Control Systems

A hydraulic version of a Deadman system does not currently exist. While design of one would not involve any special technology, it would require the comprehensive development and testing associated with any ocean floor systems. In concept, it would automatically shut in the wellbore if there were a loss of a hydraulic supply pressure and perhaps additional hot-line pressures from both pods in the LMRP. It would have armed and disarmed modes analogous to the MUX/EH versions. If armed and upon loss of all designated monitoring pressures, activation would close a designated function (shear ram, pipe ram, or an annular in the BOP stack. Hydraulic power would be obtained from LMRP and/or BOP stack mounted accumulators.

It is possible for a single system to have combined Autoshear and Deadman capabilities

It is possible for a single system to have combined Autoshear and Deadman capabilities, and in fact some Deadman Systems are so designed.

2.12.8.4 System Capabilities

	Hazard Scenario Handled Successfully?		
System	**LMRP disconnect**	**Riser/flex joint failure with loss of BOP controls and power fluid**	**Riser/flex joint failure with loss of BOP controls only**
Autoshear	Yes	No	No
Deadman	No	Yes	Yes*

* - Bleed power fluid at surface

See Systems Pros and Cons on following page.

System Type	Pros	Cons	Issues
General for Both Deadman and Autoshear Systems	+ Increase the fail-safe degree of subsea BOP systems + Promptly shut in well in an emergency / unplanned disconnect situation – Deadman/Autoshear systems respond immediately without need for human intervention (provided the system is armed)	– May require additional subsea accumulator bottles to function, and sufficient BOP stack space on the LMRP and/or BOP Stack may not be available – Limited experience with these systems to establish reliability – Concern with functioning at the wrong time – Increasing risk of failure with increasing system complexity – Adds control functions (limited number on existing systems)	• Cost/time to upgrade rig systems • Need flexibility to select best function to secure well for various rigs, i.e. blind shear, pipe, or annular • Pod plumbing restrictions • Function testing requirements
Autoshear Systems	+ Currently installed on some rigs + Can be applicable to any rig; i.e., hydraulic control or MUX/EH systems + Does not depend on battery life	– Will not activate in a parting of the riser scenario	
Deadman Systems – MUX/EH BOP Control	+ Commercial systems are now available + Systems have been built and are in operation	– Does not work if stingers are separated – Cannot secure the well if the LMRP separates from the BOP stack; e.g., it will not secure the well in the event of an accidental unwanted disconnect of the LMRP because control fluid must pass through the pod valves and stingers – Must add subsea volume (bottles) or take away from existing capacity (No existing designs/equipment to share bottle capacity) – Relies on battery power	
Deadman Systems – Conventional Hydraulic Control	+ Design for this type of system should be straightforward	– No systems currently available; R&D would be needed to develop operational equipment – Limited control hose bundle capacity for pilot line functions probably prevents installation on some BOP control systems.	• How to provide disarm and arm function?

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2.12.9 Acoustic Backup System

An emergency Acoustic BOP Control System is intended to provide backup operation of critical BOP functions. The system is separate from the primary controls and is intended to be used only in the event of loss of the primary BOP control system and is not intended to prevent accidental disconnect of the LMRP.

Acoustic system is separate from primary controls and is used only when loss of the primary BOP control system occurs
Acoustic system is not intended to prevent accidental disconnect of the LMRP.

Acoustic BOP controls are unaffected by any damage to the primary hard-wired system. These are remote sonar systems using coded pulse or burst signals, with frequencies in the 5-40 kHz range. Systems consist of a surface unit that is fixed or portable or both (rechargeable), thru-hull mounted transducers and/or dunking transducers and subsea transceivers and hydraulic control pod mounted on the subsea BOP stack. The electro/hydraulic subsea module is interfaced with the primary BOP hydraulic control system.

2.12.9.1 Design Components

Acoustic technology enables a communications link between the surface and subsea equipment to remotely operate the BOPs. Components of a system include:

- Multi-frequency command signals
- Directional subsea transducers
- Error checking, correcting (FEC) and reporting
- Permanent and portable surface controls
- Hull mounted and "over the side" dunking transducers
- Stack mounted acoustic-hydraulic control pod
- Large volume subsea accumulators

Manufacturers of acoustic BOP controls systems claim that these systems can be reliably controlled under difficult acoustic and environmental conditions, with operating depth ranges to 3500 meters. All acoustic telemetry system performance will depend on the signal to noise ratio at the

receiver. This receiver could either be the receiver at the surface or on the stack. Water depth limitations are primarily due to the reduction in signal due to extended transmission path and additional noise due to location with respect to surface thrusters, etc. The manufacturers of acoustic BOP control systems only specify water depth capability once the noise at the receiving elements is known. Most current systems in operation today are designed to operate to the depths mentioned above with an assumption of "normal" noise levels at the surface.

Water depth limitations are caused by signal reduction due to extended transmission path and additional external noise (surface thrusters, etc.)

There is a common misconception that the above statement means that these systems are suitable for use in blow out conditions. Users and manufacturers agree that the possibility of actuating a stack mounted acoustic telemetry system once a well is flowing is minimal to non-existent. They see the main use of an acoustic system as a means to be able to shut in the well as soon as possible after loss of the primary control.

2.12.9.2 Historical Problems / Unproven Capabilities

The following are some of the historical problems associated with Acoustic BOP control systems:

- Older generation systems suffered failures due to housing integrity, battery life and component reliability issues causing a loss of confidence by the drilling community. These systems date from the mid-1970s.
- General maintenance and weekly testing were dropped due to the liability associated with such a system failure once the stack was deployed.

Loss of communication, signal interruption or distortion caused by:

1. **Noise.**

   As mentioned above, noise affects acoustic telemetry and positioning systems, causing loss of communications. All acoustic telemetry systems require a specific signal that is greater than the in band, or in channel noise that the receiving device is operating

within. If the noise level rises such that the signal cannot be detected, then communications are lost. The perception of noise also manifests itself due to additional attenuation of signals. One of the more common forms of signal attenuation is air. Thrusters operating at high tip speeds under DP drilling vessels cavitate the surrounding water, causing "clouds" of aeration within the water and causing additional attenuation of the signal over standard attenuation coefficients.

Noise can come from many sources:

a. Drillstring impacting riser -- low frequency

b. Thruster noise – fixed speed variable pitch thrusters are far noisier than fixed pitch variable speed thrusters

c. ROV generated noise

d. General field noise from additional vessel

e. Self noise due to reverberation of transmitted signals from nearby structures

f. Other users in drilling locality with acoustic systems that use the same, or similar frequencies

2. **Line of sight**

The two fundamental causes of failure of acoustic telemetry systems are noise and the lack of acoustic line of sight. That is, the two communicating transducers/transceivers must be able to acoustically "see" each other.

Stack mounted components have not always been located such that clear line of sight to the surface is present. These problems are solved with current generation systems with the deployment of dual stack mounted transceivers on arms such that clear line of sight to a single surface transceiver is possible regardless of the relative geometry of the stack and the rig mounted transceiver.

3. **System accumulator capacity**

   Some of the older systems that we have taken to depths greater than initially designed for suffered due to insufficient accumulator volume. Designing the accumulator volume for the operational depth solves this problem.

4. **Actuation acknowledgment**

   Various methods are available dependent on BOP manufacturer for detecting the actual movement of the hydraulic actuation element (valve). The acoustic system interfaces into a solenoid that drives a pilot valve. Some systems read back the pressure at either side of the primary control valve. Some of the older systems had no read and hence could not confirm the actuation. Some systems still suffer due to minimal feedback as to actuation. Testing solenoid actuation without actuating is still a current issue.

No fully effective well control system is discussed within this document. If an acoustic backup system were to be considered fully effective, it should be able to function under the following conditions:

- Harmonic vibration of riser from loop currents -- noise issue
- Mud clouds from loss of riser fluids -- transmission path issue
- Gas plumes, debris and wellbore fluids -- transmission path issue
- Noise from open flowing well -- noise issue

As the noise and transmission path issues are unknown due to lack of data, the manufacturers within this sector cannot evaluate or design systems with a greater knowledge of such failure scenarios.

Once the riser is parted and the MUX cables are parted, acoustic, deadman and ROV intervention methods are the only control options available.

Some users report that these systems have a poor operating history and are generally considered to be unreliable with the lack of any history of successful testing or operation in actual blowout conditions.

Some users (Brazil) report reliable operations from current generation systems with weekly tests being a contracted requirement of operations. The reliability record of recent generation systems is short due to the new build programs only recently deployed.

There has been one documented failure case off the East Coast of Canada, of an early generation system where three unsuccessful attempts were made to close the shear rams with an acoustic control system in a Well Control situation.

Regulations / Requirements

The only Regulation identifying the requirement for an Acoustic BOP Control System is the Norwegian Petroleum Directorate (NPD) Acts, Regulations and Provisions for Petroleum Activities.

Re. Section 31, Requirements relating to blowout preventers with associated equipment

l) When drilling with blowout preventer system installed on the seabed, an acoustic or alternative control system for operation of pipe ram preventers, shear ram preventer and connection for marine riser shall in addition be installed.

The accumulators shall have sufficient capacity for closing of two (2) pipe ram preventers and one (1) shear ram preventer, as well as opening of the riser connection, plus 50%. The necessary loading pressure for the operation depth in question shall be used as basis for calculating the capacity.

Re. Section 50, Testing of equipment for wells and well control

Blowout preventers shall be pressure tested every 14 days, with exception of the shear/blind rams, this will also include function testing of the acoustic system.

In Brazil, Petrobras **requires,** by contract, that all Dynamic Position (DP) rigs have acoustic BOP Controls for Lower rams, Upper rams, Shear rams, Wedgelocks (if necessary) and Riser connector unlatch. In ONE case they have allowed the use of an Emergency Hydraulic Backup System (EHBS).

The acoustic system is tested on surface during BOP test, but only the shear rams are tested with the acoustic controls once the BOP is landed on bottom.

Other regulatory bodies who do not require acoustic control systems are HSE, MMS, COGLA and Canada-Newfoundland Offshore Petroleum Board.

Conclusions

Acoustic position reference equipment has improved over the last decade as evidenced by the number of DP vessels using this type of equipment as their primary position reference. Operational experience with current generation acoustic backup BOP control systems is still limited.

Operational experience with current generation acoustic backup BOP control systems is still limited

In reviewing the state-of-the-art for BOP acoustic controls, significant doubts remain in regard to the ability of this type of system to provide a reliable emergency back-up control system during an actual well flowing incident.

The added complexity of an acoustic system can only be justified if it brings about a significant improvement in the safety of the well and can be relied upon to work whenever required. In addition it must not introduce a reduction in primary control system reliability, including avoidance of inadvertent actuation.

The addition of acoustic control equipment on the BOP stacks plus the large volume subsea accumulator requirements for deepwater acoustic system operations makes it difficult to add acoustic controls to existing BOP stacks.

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3.0 EQUIPMENT

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Chapter 3. Equipment

Equipment Subcommittee
David Bruce (Chairman) – Diamond Offshore Drilling, Inc.
Bryce Dickinson – Marine Drilling
Hugh Elkins – Varco Shaffer
Richard Frisbee – Oceaneering International
Earl Robinson – BHP Petroleum (Americas), Inc.
Joe Roche – Brissoneau & Lotz Marine

APV	Air pressure vessel
AX/VX	Ring gasket
C&K	Choke and kill
DP	Dynamically positioned
ECD	Equivalent circulating density
EDS	Emergency disconnect sequence
GOM	Gulf of Mexico
LMRP	Lower marine riser package
LVE	Low volumetric expansion
MMS	Minerals Management Service
MODU	Mobile offshore drilling unit
MUX	Multiplex
ROV	Remotely operated vehicle
TJ	Telescopic joint

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3.1. BOP Arrangement for Deepwater Operations

3.1.1. Summary

This section captures some of the differences, subtleties, and considerations for BOP issues in ultra deepwater, both in a moored and a dynamically positioned (DP) operation.

3.1.2. Number of Rams in a Deepwater Stack

The number of rams desired will be dependent on several different considerations. As for all rigs, the number of pipe rams depends on number of sizes of drillpipe in the drillstring, operators preference, and local regulatory agencies.

Typical floating drilling rigs have 3 pipe rams and one sealing blind shear ram

Generally, and as required by the Minerals Management Service (MMS), two rams are required for the larger size drill pipe and one pipe ram for the smaller size, which is usually a stinger for drilling through small liners. Typical floating drilling rigs have 3 pipe rams and one sealing blind shear ram.

Over the years, this arrangement has served the industry well in the shallower water depths. However, as rigs move into ultra deepwater, things that were standard in shallow water, and perhaps taken for granted, can change. Some of these things are clear to the engineer and operations people, but some can be rather subtle.

Hydraulics becomes an issue in deepwater drilling due to large hole sizes and deep target depths

As rigs move in to deeper water, hydraulics becomes an issue due to the necessity of drilling large holes (14-3/4" up to 26") at a very deep depth (as compared to traditional shallow water drilling). It is not unusual to drill a 22" hole at a depth of 12,000 – 13,000 ft RKB.

Large drill pipe: 5-1/2" and 6-5/8"

For adequate hole cleaning at these depths, consideration has to be given to the use of larger than traditional drill pipe

size of 5". Many operators give consideration to 5-1/2" drillpipe and 6-5/8" drill pipe. While these drillpipe sizes pose no problem from a BOP ram standpoint, the larger sizes are generally not suitable after some casing strings have been set, such as 9-5/8", as the tool joints on the large drill pipe can cause severe equivalent circulating density (ECD), wear, and fishing problems.

Rams may be limited in the smaller ranges of pipe on the amount of weight that can be hung-off

At this point, if the operator elects to return to smaller drill pipe, it will be necessary to have at least two rams that will also seal on the 5". This could be accomplished by more ram cavities or pulling the BOP to change rams, but these are generally not thought to be the proper solutions with the availability of pipe rams that will seal on a range of drill pipe rather than just a single size. Caution should be exercised when choosing rams that will seal over a variety of drill pipe sizes because some of these rams are very limited in the smaller ranges of pipe on the amount of weight that can be hung off.

BOP must be capable of shearing and sealing on main drill pipe strings

For DP operations, it is absolutely necessary that the BOP be capable of shearing and sealing on the main strings of drill pipe that will be used. It is also highly desirable to be able to hang-off the main elements of the drillstring. This will complicate ram arrangement further, in that if two different size strings are planned to be run through the BOP stack during the course of the well, then both of these strings (6-5/8" or 5-1/2") and 5" must not only be shearable and sealable by the BOP, but if rams that seal over this range of drill pipe are used, these rams must also be capable of hanging the weight of the drill string. Again, consideration has to be given to the amount of pipe that can actually be hung off for the smaller ranges of drill pipe.

For DP operations, some operators have two sets of blind shear rams in order to have a back-up seal in the event of an unplanned disconnect. The thought is to have one set to shear, and a second set to seal in the event that the ram packer of the shearing rams is damaged. It also provides redundancy in the event of an unplanned disconnect and the subsequent loss of riser margin while drilling reservoir.

This is a judgement call and is subject to the operators in-house philosophy and policies.

Casing shear rams

Additionally, due to the exposure on DP rigs while running casing, special rams that will shear casing have been developed.

During decisions on ram number, consideration has to be given to whether the casing shear rams will shear drill pipe (some will not) and whether they will seal after shearing (most will not).

Potential use for up to six ram cavities in a DP operation

If the operator also chooses to install a set of rams that will shear casing, (but are not capable of sealing), this accounts for three ram bodies before even considering pipe rams. As discussed above, most operators desire three pipe rams for stripping, general flexibility, and in some case regulatory requirements. Therefore it is conceivable that some operators could desire up to six ram cavities for a DP operation.

3.1.3. BOP Height

BOP height and substructure clearance

BOP height may create the potential for substructure interference. Therefore, number of rams becomes quite important, particularly when working with a guidlineless-less system and the corresponding need to have some type of funnel/re-entry system for the LMRP. To be able to reconnect with some heave, it is necessary to have a guide funnel or other system that will allow the LMRP to realign. This requires sufficient clearance under the substructure for the system to be able to be separated.

Potential bending moments placed on stack

Design stack height and the number of rams in deepwater drilling are also affected by the potential bending moments placed on the stack. This is another factor to be considered when designing the overall height of a subsea BOP stack

An effective way to consider lowering the stack is to consider only one annular. While it has been the custom in

the past to have two annulars, and is so recommended by API, one annular is a feasible option for two reasons:

1. reliability of annulars is greater than ever in the industry
2. most deepwater well control procedure call for hanging the drill pipe off, which will reduce wear on the annular, and also be a safer operation

3.1.4. Placement of Rams/Outlets

The location and placement of pipe rams is not determined by hard and fast rules. Ram location should be thought out in order to accommodate the specific situation. It is generally accepted that blind shear rams should be at the top of the stack to allow for well control and flexibility in drill pipe hang-off and drill pipe shearing.

The following should be given consideration:

Considerations for Placement of Rams/Outlets	
1	Will there ever be a desire to strip ram-to-ram?
2	Hang-off point should be located so that if it is necessary to shear the drill pipe, there is adequate room between the hang off ram and the shear ram to leave an adequate fishing neck and not shear in the upset.
3	Retain the ability to use the kill line as a choke line in the event that the choke line plugs.
4	Possibly use the lowermost pipe ram as an emergency ram which would not be used for normal well control operations.
5	Consider having two sealing blind shear rams for DP operation so that back up will be available in the event of an unplanned disconnect.
6	Due to the potential for large amounts of gas at atmospheric conditions (trapped gas), an outlet below the upper annular should be considered to simplify stack clean out operation following well control procedures.
7	Casing shear ram location with respect to blind shear(s) should be carefully considered for DP operations since some casing shears do not seal the wellbore. • Consideration should be given to the possibility of casing being stuck in the BOP when having to emergency disconnect and also for sheared casing clearing the stack prior to the blind shears closing. • In the event of loss of power, the drawworks would be unable to lift sheared casing above the blind shears if the blind shears are above the casing shear rams, leaving open the possibility of the blind shears closing on the casing and neither shearing or sealing-leaving the well bore open and live. • Conversely, with the casing shears above the sealing blind shear rams, if casing becomes stuck in the BOP and has to be sheared, the casing may not "slump" enough to clear the sealing blind shear rams, again leaving the well unsecured since the sealing blind shears could not cut and seal on the casing.

Table 3-1 Considerations for placement of rams/outlets

Outlet below each sealing ram

Generally, consideration should be given to having an outlet below each sealing ram, and also an outlet below the upper annular. The placement and limitations of an outlet below the lower ram should be evaluated. It should only be used as a kill line for monitoring pressures, and never used as a choke line except as a means of total last resort.

3.1.4.1. Blind shear rams

The API requirements for qualifying blind shear rams call for grade G pipe to be sheared and allowed to fall away from the rams before pressure testing. These requirements are less than is required for DP operations, where frequently very high strength pipe is used, and the pipe is hung off in an emergency disconnect scenario, not allowing for the stub to fall away from the rams.

Splintered, jagged cut on drill pipe may damage ram packers

This is a more severe test, since this type of operation could result in a much more splintered, jagged cut on the drill pipe, and this splintered pipe, which remains at the ram location since it is hung-off, could damage ram packers.

Sealing blind shear manifolded separately to apply higher pressure to operator

Consideration also has to be given to having the sealing blind shear manifolded separately from the rest of the stack functions so that higher pressure (up to 3,000 psi) can be applied directly to the operator and not the 1500 psi generally carried in the control manifold. This will enhance faster and surer shearing.

3.1.4.2. Casing shear rams

Function and shear time affected by operator size and fluid requirements

When utilizing casing shear rams, the location in the stack is quite important as discussed above. Casing shear rams generally require very large operators which use large amounts of fluid, and hence take somewhat longer time to function and shear. This timing needs to be recognized when designing an emergency disconnect sequence.

As mentioned above, the casing shear may be manifolded separately from the rest of the stack functions so that higher pressure (up to 3,000 psi) can be applied directly to the

operator and not the 1500 psi generally carried in the control manifold.

Connector strength may be greater than riser strength

3.1.4.3. Choke/kill connectors

The strength of choke/kill line connectors is particularly important on DP operations. These connectors can have a strength greater than riser strength. In the event of a failure of the connectors to release in an emergency disconnect, there could be a catastrophe. If these connectors are very high strength, consideration should be given to making the hydraulic lines redundant for some form of back up.

3.1.4.4. Wellhead connectors: bending loads

See also *Well Planning, 1.1.8.3, Bending Load Rating*

In the event of loss of station keeping ability and failure to disconnect in a timely manner, tremendous bending loads can be imparted on the BOP stack and wellhead. Consideration should be given to calculating these bending loads to ensure that equipment chosen, including wellheads, connectors, and BOP flanges, can withstand these bending loads and still function at their respective rated pressures.

Hydrostatic pressure of seawater may cause connectors to become hydraulically locked on wellhead

The connectors can become hydraulically locked on the wellhead by the force caused by the hydrostatic pressure of the seawater in very deep water. Steps should be taken to mitigate this risk,

3.1.4.5. Flange bending strength

Bending strength of flanges must be considered in deepwater options. Bending moments should always be calculated for deepwater operations to ensure the BOP integrity will remain sound for station keeping incidents

Bearing in load ring must absorb and dissipate most of the torque generated as rig turns

3.1.4.6. Bearings in load rings

As the ship weather vanes into the environment, the bearing in the load ring used on DP rigs must be able to absorb and dissipate most of the torque that is generated as the rig is turned. A defective or poorly maintained bearing could result in an unacceptable amount of torque being transmitted to the riser, which could damage the riser, stack, or conductor/structural casing.

3.1.4.7. Location of LMRP split

The LMRP split is generally located below the first annular. Consideration could be given to using an integral double annular if substructure height is an issue and two annulars are desired. This would place the LMRP split below both annulars. The implications of having both annulars in the LMRP should be considered when planning for emergency disconnects in a DP operation.

Effects of temperature on BOP elastomers

3.1.4.8. BOP elastomers

In the deepwater environment, the performance of BOP elastomers can be subjected to a wide range of temperatures. At ambient temperatures, elements may fail to extrude and flex properly, compromising a seal. On some occasions, rams have had to be functioned several times in order to "loosen" the elastomer in order to get a proper test.

Conversely, for a deepwater testing operation, depending upon reservoir depth and temperature, and flow rates tested, these elements can be subjected to very high temperatures

Both of these circumstances have to be considered when designing elstomer elements for a deepwater operation.

3.1.4.9. Failsafe valves

Failsafe valves at great depth are not 100% failsafe, but rather generally failsafe assist.

3.1.4.10. Latching up in deepwater

Latching up in deepwater is best accomplished with an ROV. Although "bomb shell" cameras can be used, consideration should be given to having an ROV on board.

3.1.4.11. Bolt arrangement

Hydrogen embrittlement

While high strength bolts may be warranted to counteract bending loads on the BOP stack, the possibility of hydrogen embrittlement damaging high strength bolts should be considered. The source of hydrogen is generally from sacrificial anodes. This phenomenon of hydrogen embrittlement of external components has been observed.

3.1.4.12. BOP pressure ratings

In ultra deepwater, consideration must be given to mud weights and BOP pressure ratings when testing. The differential pressure of the mud vs seawater mud must be considered when designing BOP test pressures in ultra deepwater.

Differential pressure of mud vs seawater mud

For example, while drilling in 8000 ft of water with 15 ppg mud, the BOP body is subjected to a differential pressure of 2,700 psi. For a BOP rated to 15,000 psi, the maximum test pressure for these conditions would be 12,300 psi.

3.1.4.13. External Pressure Loading of BOP Equipment

Under certain situations, subsea BOP stacks can have their internal pressure reduced below the ambient hydrostatic sea water pressure:

- Lost returns in wellbore if severe enough to cause significant drop of riser mud level
- Gas in riser unloading mud (refer to Section 2.6)
- During removal and venting of trapped BOP gas (refer to Section 2.5.5)

- With horizontal trees, during completion operations with tree access valves open and BOP closed, i.e. to pump unloading gas down C&K lines.
- In production testing operations, if a reversing valve is opened with the BOP still closed, and if the tubing is largely evacuated, i.e., a gas well test, the annulus fluid may fall faster than it is being refilled from the surface, via the choke and kill line.

In deeper water, the magnitude of this external pressure loading may exceed the capability of the BOP rams (i.e., pressure energized bonnet seals), BOP connections, hydraulic connectors, C&K jumper lines across the lower flex joint, etc. While the leakage of sea water into the BOP equipment is not significant problem per se, there is the potential for the leakage to damage the seals or otherwise affect the pressure integrity. The manufacturers can be consulted on the capability of the various equipment items.

The occurrence of this type of loading should be quite rare, so external pressure capability is not a necessary equipment specification. However, if such a loading occurs at a level above the assessed capability, a BOP stack body pressure test can be performed to confirm that integrity has not been lost.

3.2. Choke Manifold Considerations

3.2.1. Summary

This section lists some of the considerations for choke manifolds when operating in deepwater.

3.2.2. Overboard Lines

Overboard lines from the choke manifold would allow venting fluid directly overboard if the mud is badly contaminated and will contaminate the remaining mud system.

3.2.3. Mini-Trip Tanks

Safe flow checks via C&K lines

Consideration should be given to installing a small measuring tank directly at the choke manifold for the purpose of both stripping and monitoring flow from the choke kill line. This would allow for safe flow checks, via the choke and/or kill line, without having to unload a choke or kill line in order to fill up the mud drainage systems and flowlines back to the regular trip tank. This would also allow for flow checking with out the fear of allowing any gas into the riser.

3.2.4. Low Pressure Gauges

Due to the small margins between mud weights and leak off in ultra deepwater, consideration should be given to installing accurate low pressure gauges on the manifold that can read low pressures (50-100 psi) accurately

3.2.5. Set-up for Riser Gas

See also *Well Control Procedures, 2.6, Gas in Riser*

Consideration for handling riser gas should be given to choke manifold design. This could include provisions to use the riser mud gas separator (if one is available) in addition to the regular mud gas separator.

Monitor riser on trip tank even when diverter is closed
Riser mud/gas separator

While circulating out a kick through the choke manifold, consideration should be given to having the flow lines and diverter system built so that the riser can constantly be monitored on the trip tank, even if the diverter is closed.

3.3. Deepwater Riser Considerations

3.3.1. Summary

Riser operations in deepwater could be considered the most critical among a large number of critical operations. Riser management is the key to a successful deepwater operation.

Very large tensions are required for deepwater operations, and the potential for unplanned disconnects and drive offs further complicates riser management. Following are key issues that should be considered when planning riser operations in deepwater.

3.3.2. Riser Cleaning

Hydraulic riser cleaning (boosting) can be accomplished by pumping down either the choke and kill lines, or more preferably, a dedicated boost line if riser is so equipped. Recent riser orders have most boost lines at 4" ID, with a 5,000 psi rating.

Dedicated boost line

In the absence of a dedicated boost line, pumping down through the choke and kill lines has been field proven. Anticipated increased choke and kill valve problems related to this operation have not been experienced.

Mechanical Cleaning

This is required prior to some completion work. The most effective method for main body cleaning is a wire brush "pig" built around a drill pipe pup joint that can be tripped through the riser while it is in service.

Newer risers have internal ceramic coatings which may be damaged by harsh cleaning methods

Various companies offer pressure washing services to clean riser while it is racked. Historically on older style risers, the choke and kill lines were cleaned internally with a rooter router or frayed wire rope. The latest generation risers often have ceramic coatings applied internally, negating the need

for such cleaning. It is important to note that harsh mechanical cleaning could conceivably damage this coating.

3.3.3. Boost Lines

While it is possible to utilize C & K lines on older riser, a dedicated boost line is considered essential on new riser ordered for deepwater applications. Dimensions are individual company's preference; and the most common sizes appear to be 4" ID with a 5,000 psi rating.

3.3.4. Boost Line Valves

In the event of a gas influx into the riser, a valve is required immediately above the stack in the boost line. A valve of some sort is also required in the event that the boost line develops a leak, and has to be isolated.

Check valve or conventional stack valve may be used above the stack in the boost line

As this line does not need to be pressure tested, a simple check valve will suffice. A conventional stack valve can also be utilized for this application, which will give the option of testing the line. The check valve has the advantage of simplicity and automatic actuation should the boost line be unused, and gas (or any other influx) attempts to migrate up the boost line.

3.3.5. Anti-Collapse Valves

Combating riser collapse in the event of full or partial evacuation of mud can be addressed in two ways:

Wall thickness

- A riser main tube wall thickness that can withstand any differential pressure that can be reasonably anticipated

Valve for seawater influx

- The addition of a valve that will automatically allow the influx of seawater in the event of mud evacuation of the riser

Both solutions have their relative merits. Wall thickness can appear to be a very simple solution. However, in ultra deepwater potential differential pressures are such that it is

not a reasonable solution. While the additional steel cost can be significant, the additional flotation required may make this solution unreasonable.

Determine maximum expected differential pressure

Considerable effort should be spent determining to what extent the riser will/can be evacuated. This differs from DP to conventional mooring. Once a maximum expected differential pressure be decided upon, the relative merits of the two systems can be evaluated and the optimal solution for a specific application be determined.

3.3.6. Tracking of Service

Time in service and position in riser string is especially critical for riser in fleet wide service

Each joint in the riser should have a serial number, so that time in service and position in the riser string can be accurately monitored. This is especially critical when the riser is common between more than one rig and can see fleet wide service. Accurate tracking may help future problems for joints that have seen similar critical service as other joints on which problems may be identified

3.3.7. Inspection Intervals

The following factors should all be considered when determining inspection intervals and extents:

- water depth
- tension loads
- mud weights
- exposure to loop currents (and any VIV Criteria encountered versus design criteria)
- hurricane/tropical storm hang offs
- mechanical damage-keyseating
- loss of pressure integrity
- company internal requirements/policy

3.3.8. Riser Angle Indicators

Riser angle indicator in middle of riser string

In instances where extreme current and/or environmental conditions can be anticipated, it is recommended that at least one riser angle indicator be installed in the middle of the riser string when drilling in water depths in excess of 3,000 ft. Additional indicators will allow a better understanding of conditions actually being encountered by riser during events. During conditions of extreme loop current events it may be impossible to utilize an ROV to monitor riser.

Extreme loop currents may prevent monitoring riser with an ROV

3.3.9. Diverter Housing Size

The primary driving force to determine diverter housing size is riser (flotation) diameter. While it is possible to remove the rotary table, it is normal for the diverter size to be matched to that of the rotary table.

Riser buoyancy

Ideally riser will be 98 per cent buoyant. This percentage can be reduced by adding extra tension. This solution works well on conversions but is not as acceptable on new builds. Flotation efficiency can be increased, and the diameter reduced, but there is an associated cost penalty. The present generation of new builds have utilized the 60-1/2" housing almost exclusively. In association with the larger diameter C & K lines, this allows for a 98% flotation.

3.3.10. Stress Joint in Tool Joint/Intermediate Flex Joints

During drift off or other station keeping loss events, it is possible for the slip joint to come in contact with the moonpool. In very deepwater with long risers, this collision can cause extreme stresses in the slip joint and the joint directly below the slip joint. Additional stress can be imparted to the first joint of riser below the moon pool in the event of a drive off.

Consideration should be given to a strengthened outer barrel for the slip joint.

Some analyses indicate that the installation of an intermediate flex joint directly below the slip joint can greatly reduce the stress in the riser in the event of a drive off situation.

3.3.11. Location Of Choke/Kill Termination

Contractors locate choke/kill terminations both on the telescopic joint (TJ) itself, and also on a termination joint located directly below the TJ.

3.3.12. Telescopic Joint

When landing the stack the tension joint should be spaced out so that in the case of a moored rig, a single mooring line failure and subsequent vessel offset will not cause the slip joint to bottom out. This implies that unless circumstances dictate otherwise, the TJ should be positioned in the more than half closed position. This becomes more critical for deepwater DP operations, where heave can have a significant effect on slip joint position, and have a big impact on disconnect procedures.

If the telescopic joint is not long enough to handle mooring failure offsets and simultaneous vessel heave, it is possible to manage this risk by installing real-time monitoring and calculated systems. Mooring systems can be adjusted upwind to reduce angles for both intact and damages condition within limits. Another option if angles cannot be managed is to adjust mooring lines before maximum offset occurs. The time frame for maximum offset after a mooring failure is on the order of 5-15 minutes, so that a centralized mooring control center is probably needed for this option. Another approach is to install Emergency Disconnect Systems as DP rigs have for this purpose.

3.3.13. Faring Considerations

Farings are time-consuming to install, and the various designs make a common fixing method impossible. It is most important to have an easily accessible installation platform. MUX systems eliminate one of the largest concerns, that of pod line farings. As the MUX cables are nested in the buoyancy they are protected. Historically loop currents have caused more down time due to pod line damage than to riser damage.

3.3.14. C & K End Loadings

When designing riser connections, serious consideration must be given to end loadings imparted to the connections when the C&K lines see pressure. These loads have always been there, but with the much larger cross sectional areas of the ultradeep riser's C&K lines, this has become a serious issue.

In addition to design, consideration should be given to testing C&K lines simultaneously to avoid imparting eccentric loading on the riser. In kill situations in is advantageous to have equal pressures in both lines, for the same reasons. The procedures committee will further address this issue.

3.3.15. Upper and Lower Flex Joints

Upper and lower flex joints are requirements in deepwater due to the offset potential of the rig.

Flex Joint Strength

The following considerations should be given to flex joint strength:

1. Strength in tension due to the high top tensions required on the riser

2. Burst strength due to the high differential pressures in deepwater and high mud weights
3. Collapse
4. Strength in torsion for DP operations (weather vaning can cause tremendous torsional loads to be transmitted to the riser)

3.3.16. Riser Hang Off

Strong consideration should be given to have the ability to hang the riser off when disconnected. This can be confirmed by riser analysis. This will eliminate the potential problem of the riser getting out of sync when disconnecting in heavy seas, and eliminate the potential problem of the riser tensioner ropes jumping a sheave.

3.3.17. Riser Analysis

Riser analysis is very important in deepwater operations. Due the extremely large top tensions required, there are many parameters that have to be analyzed. The following should be considered for a deepwater operation:

- Connected analysis
- Disconnected analysis in heavy seas
- Disconnect analysis in a drift off /drive off situation
- Loop current analysis

Riser analysis has to be done in conjunction with station keeping analysis to determine how the riser will react for broken mooring lines, drift off, or drive off scenarios.

Due to the criticality of the riser to well control in deepwater, the need for in depth analysis can not be over emphasized. There is a large amount of literature available concerning riser analysis, including API RP 16Q It is highly advisable that in-depth studies of the riser are done.

3.4. Deepwater Diverting Considerations

3.4.1. Summary

Diverter systems are designed to redirect the flow of shallow gas which may be unintentionally experienced during top hole drilling (see API RP 64). The diverter system should safely divert the flow away from the rig floor to overboard exhaust. Use of a diverter for its intended purpose is generally limited to moderate water depths. The advantages of using a riser (and, hence, a diverter) in this situation include the following:

- Returns are available.
- Weighted mud can be used for well control.
- Treated mud can be used for hole conditioning.
- Aeration of the water beneath the vessel during a blowout is avoided.
- Air gap provides overbalance.
- No debris on sea floor.

As the water depth increases, these advantages become less significant. Hence, there is a general trend away from using the riser and diverter during top hole drilling.

3.4.2. Riserless Drilling

The deeper the water depth, the more likely it is that, without a riser, a gas plume from the well will be swept away from the vessel by currents. When drilling top hole in deepwater, the relative merits of riserless drilling include the following:

Advantages of drilling riserless

- Aeration less likely beneath the vessel during a blowout.
- Hazardous (erosive, combustible and/or noxious) flow is not brought directly to the vessel.
- Potential for fire is reduced.
- A DP vessel can be readily moved off site.
- Riser running/pulling time is saved.

Surface diverter system may serve as secondary safety device

In deepwater, the surface diverter system may serve as a secondary safety device in the event that gas is inadvertently allowed into the riser. Most floating drilling

rigs have a diverter system in-situ as the uppermost structural connection of the marine riser. As a matter of course, the diverter is standing by whenever the riser is in use. During deepwater drilling, the diverter system can serve to redirect flow of fluid that may be caused by an unexpected small gas influx entering the riser before a BOP can be closed. When using oil base mud, drill gas coming out of solution could be an acute hazard.

3.5. Riser Gas Considerations

See also *Well Control Procedures, 2.6, Gas in Riser: Riser Diverter*

3.5.1. Summary

Widespread shallow geopressured formations

As is intuitively obvious, the possibility of free gas getting into the riser in very deepwater locations is quite high and is probably the one event that is most dangerous to rig floor personnel. This is of particular concern in the Gulf of Mexico due to the preponderance of shallow geopressured formations. It would be quite possible to encounter a geopressured zone at a depth of 2,000 ft (or even shallower) below the mudline. If this situation occurs in a water depth of 6,000 ft with the BOP and riser run, the possibility of gas in the riser becomes quite real.

3.5.2. Danger of Free Gas in the Riser

Free gas in the riser represents one of the most dangerous situations on a rig from a stand point of personnel safety. It is also quite critical as related to rig equipment. Irrespective of the threat to personnel, there also exists the possibility of collapsed and/or parted riser, fire on the rig floor, and damage to the riser hang off system.

Very elementary calculations show that 10 bbls of free gas would expand to a volume in excess of 2,500 bbls of gas at atmospheric conditions. History has shown that this gas could unload violently as it approaches the surface. It is also quite possible that if some gas does get in the riser, the BOP has been shut-in for a well control situation.

As the gas slowly migrates, (at a generally accepted rate of 1,000 ft per hour), normal well control operations are taking place, such as weighting up, pumping out the kick, etc. It is not out of the realm of possibilities that this slow migration of gas in the riser could go unnoticed as these other activities are taking place, and the gas will begin to

unload before anyone notices it. It is these conditions that are the most dangerous.

3.5.3. Diverter System Design

When designing a diverter system for a rig, consideration should be given to designing the system so that mud can be degassed and returned to the mud pits while the element is closed. While it is paramount that the system never be completely shut-in, it is possible to design a system that will return mud to the active system while allowing for gas to handled also. This can be done be either having a riser mud/gas separator as part of the diverter system, or having mud return lines beneath the diver to lines to allow whole mud to be returned to the system while still allowing the gas to be exhausted overboard.

Slip joint packing is weak link in riser system

The slip joint packing is one of the weak links in the riser system when handling gas in the riser. Equipment has been designed to install an annular element directly below the slip joint to allow a low pressure shut in of the riser and allow the mud to be returned to the choke manifold.

This system has not been yet used in the field, but shows promise. There are many riser design considerations that have to be addressed before this system is safely installed.

3.6. Deepwater Control Systems Considerations

3.6.1. Summary

BOP control systems become very complex for deepwater operations. As rigs move into deepwater, response time becomes critical, and probably reduces traditional hydraulic control systems to obsolescence. Following are points to be considered when designing a deepwater BOP control system.

3.6.2. Closing Times: Hydraulic vs Multiplex

Standards for BOP closing times

There are two generally accepted industry standards for subsea BOP closing times:

- API RP-1 6E
  45 seconds for Ram Close
  60 seconds for Annular Close
- NPD Requirements Appendix A
  30 seconds for Ram Close
  45 seconds for Annular Close

Using an LVE type umbilical hose and pressure bias system, hose lengths up to 6,000 ft can stay within the required closing times.

Reaction time (solenoid firing time) for MUX systems varies from less than 1 second up to 7 seconds with umbilical lengths up to 10,000 feet. Fluid flow times remain as above.

3.6.3. Consideration of Third Pod

Due to timeliness of pod maintenance some feel that a complete spare pod should be available. Having a spare pod allows for rotation of pods on the stack for more complete preventative maintenance of these more complex systems.

3.6.4. ROV Intervention

- Recommended for major functions such as shear rams to allow operation with loss of MUX Control
- Unlocking of LMRP connector and other functions for retrieval of LMRP
- Unlocking of wellhead connector for stack retrieval
- Operation of LMRP and wellhead gasket release
- Dumping pressure from subsea accumulators

3.6.5. Volumes/Bottles Closing Fluid

Published standards for the amount of usable fluid available in an accumulator system

There are two generally accepted published standards for the amount of usable fluid to be available in an accumulator system. These are as follows:

- API RP- 1 6E (Most widely used except North Sea and Brazil)
- NPD Requirements appendix A (North Sea and Brazil)

These requirements have specifications that are based on opening and closing of all functions a set number of times with only the accumulator bank used for pressure. After this set number of openings and closings, the accumulator must still maintain a certain pressure above pre-charge pressure.

It should be noted that these requirements are only for overall accumulator volume, surface and subsea. There are no requirements by regulatory agencies for the number of bottles on the stack for a subsea BOP. Generally, bottles have been added to stacks to enhance closing times. With multi plex systems, and the fast response times of the pilot signal, it could be possible to eliminate bottles on the stack. Consideration should be given to the size of the control fluid line on the riser if eliminating bottles on the stack is considered. A larger line naturally enhances fluid transfer. However, for DP operations, the decision to eliminate bottles on the stack should be taken with care in light of the requirements for fluid volumes for an emergency disconnect sequence.

Bottles must be located on the BOP stack itself to activate a deadman system, if used.

3.6.6. Volumetric Rating of Subsea Accumulator Bottles

Often subsea accumulator bottles are installed to improve the closing time performance of BOP control systems and to provide backup power fluid for critical functions for the event that surface supply is lost.

Also, some backup control systems such as deadman, autoshear and acoustic types require subsea accumulator bottles to provide pressurized hydraulic fluid to power the programmed BOP functions. These backup subsea bottles may be dedicated to the particular system or may be shared by primary and backup BOP control systems depending on the design strategy.

The subsea accumulator bottles are precharged to an initial pressure with a gas and then the power fluid is pumped into the bottle up to the design operating pressure, thus compressing the precharge gas. The precharge gas is usually nitrogen, but helium is starting to be employed in deepwater, for reasons discussed later.

The number of needed accumulator bottles, or more specifically volumetric capacity, is driven by the volume and pressure requirements for the power fluid to operate assigned functions.

Types of Accumulator Bottles Used on Surface and Subsea Installations

There are three types of accumulator bottles used in both surface and subsea installations:

- **Bladder type** - where an elastomeric 'balloon' separates the precharge gas from the hydraulic fluid
- **Float type** - in which a metal chamber floats on the hydraulic fluid. When all of the fluid has left the bottle, the float pushes down a valve closed at the bottom of the bottle to prevent precharge gas from entering the control system. The floats are not evacuated chambers (avoids high collapse pressure), but rather are in effect an open-top design that performs like a small boat.

- **Piston type** - a piston with seals along the bottle wall separates the gas from the hydraulic fluid.

Traditionally, accumulator bottle volumetric capacity has been determined assuming an isothermal, ideal gas expansion of the precharge gas from the operating pressure down to the minimum operating pressure. This is a simplification. In reality, the precharge gas cools substantially during the expansion (known as adiabatic cooling). If all of the power fluid is needed before heat transfer from the surroundings can restore the gas temperature, there would be about a 35 percent loss of volume capacity. Because the thermal conductivity of gas is low, re-heating is a relatively slow process. Therefore, most design guidelines call for 50 percent reserve which compensates for the cooling effect loss.

This ideal gas assumption using a 50% reserve is adequate for the pressure range used in surface accumulators (from 1000 to 3000-5000 psi).

Deepwater Impacts on Subsea Accumulator Bottles

Subsea bottles should be precharged to the sum of (a) the minimum operating pressure plus (b) hydrostatic water pressure. Increasing water depth has several impacts on the performance of subsea bottles:

- **Volumetric Efficiency:** The compressibility behavior of the precharge gas at the higher pressures increasingly deviates in an adverse manner from ideal gas, such that actual compressibility properties may be needed.
- **Volumetric Efficiency:** The adiabatic expansion effects may also increase. If volumes are needed over a short time frame, the adiabatic effects should be explicitly considered. (A quantative example of these two volumetric effects is in the table below.)

  Note: Properties (volume, density, entropy, etc as a function of pressure and temperature) of nitrogen and helium are available from the National Institute of Science and Technology (NIST) from the website http://webbook.nist.gov/chemistry/fluid/.

- **Float-type bottles:** The density of the nitrogen increases with pressure such that float-type accumulators may need larger floats to avoid downflooding and sinking through the hydraulic fluid, prematurely closing the bottom valve.

- **Float-type bottles:** At high pressure and cool temperature (pressures over 4000-5000 psia at 45 degrees F.), nitrogen and water can form hydrates, an ice-like material. In float-type accumulators, nitrogen gas is in direct contact with the water-based power fluid around the perimeter of the floats. Although hydrates form slowly, they can ultimately impede the movement of the floats or even form a plug. As fluid is removed and a pressure difference develops, accumulators floats may then break free and move at high velocity, potentially damaging float and valve mechanisms. Research and development may provide a solution to prevent this freezing, possibly using a hydrate inhibitor/antifreeze in the accumulator fluid, or as an initial precharge
- **All types of bottles:** When the bottles move fluid to the system, the precharge gas expands and cools. Upon complete fluid withdrawal, the gas temperatures will drop to -20 to -52 degrees F, depending on the type of gas (see table below). The temperature will be restored by the sea water environment. While the steel bottle walls are a good heat conductor, the gas itself is poor, such that re-heating of the gas will be slow, perhaps 15 to 30 minutes. At these temperatures, water in contact with or close proximity to the gas may freeze. To what extent this causes problems in the various accumulator types is not yet known. As with the hydrate issue above, research and development may provide an anti-freeze method.
- **Piston-type accumulators:** These have limited clearance tolerance along the piston/bottle along the annular space in order for the seals to function, and high temperature changes and transients may cause binding, depending on clearance distance. Also the low temperatures may cause seal problems. These issues can be addressed in design and checked in physical testing of the bottles.

Helium Precharge Gas

Helium precharge gas offers some advantages and disadvantages in deep water.

- Its physical properties at high pressure much closer to the ideal gas model than nitrogen, and offers substantially better volumetric efficiency.
- It has much lower density, so that any given float design can be used at a higher pressure (compared to nitrogen).
- It does not form hydrates.
- Because of its much smaller atomic size, it leaks and diffuses much more easily. To avoid losses, seals must be appropriately designed. To reduce leakage loss, the bottles

should not be left pressured with helium but no fluid for prolonged periods of time (leave some fluid in them).

- Bladder accumulators may not be suitable for helium due to the potential for destructive gas impregnation of the bladder elastomer; testing may determine that this is not a problem.
- While achieving higher volumetric efficiency than nitrogen, for a given performance, the helium will result in colder expansion temperatures.

While the data shows that bottles efficiency is reduced in deepwater, the impact is simply that more bottles are required to provide a given volume. As long as sufficient BOP/LMRP stack space can be provided, reliable and effective accumulator capacity can be achieved.

Example of Water Depth Effect on Volumetric Capacity

Water depth: 5000 feet

Accumulator minimum pressure: 2000 psi surface basis (4234 psi precharge for subsea)

Accumulator operating pressure: 5000 psi surface basis (7234 psi subsea)

Surface and subsea ambient temperature: 45 degrees F.

Usable volume to be 50 gallons:

		Gas Volume, gallons		
	Description	Ideal Gas Isothermal	Nitrogen Adiabatic	Helium Adiabatic
1	**Bottle Volume: precharged to 4234 psi**	121	366	255
2	**Pressure to 7234 psi (5000 psi surf.)**	71	262	163
3	**Reduce pressure to 4234 psi**	121	312	213
	From step 2 to 3 = Usable volume	50	50	50
	Ratio of Usable to Nominal	2.4	7.3	5.1
	Final temperature, degrees F.	45	-20	-52
	Relative Performance vs. Ideal Gas	100%	33%	47%
	Relative Performance vs. Nitrogen		100%	144%

3.6.7. Automatic Closure in Event of Failure of Lines (Deadman System)

Catastrophic failure of the riser or unplanned LMRP disconnect

In the event of catastrophic failure (parting) of the riser or unplanned LMRP disconnect, an automatic function may be used to close the shear ram. The intention is to close the well in to avoid a potential blowout. The command to operate this function results from loss of both hydraulic and electrical power to both MUX Pods or unplanned disconnect of the LMRP.

3.6.8. Working Pressure for Control Systems

The working pressure for control systems is generally 5,000 psi for water depths greater than 5,000 ft due to the inefficiency of accumulators at this water depth and the high nitrogen precharge pressures required. Due to the necessity to precharge subsea bottles at the surface, working pressure of the bottles can be required to be quite high.

Accumulators charged to 5,000 psi differential on the sea floor must be vented before retrieving the BOP stack to the surface.

3.6.9. Pressure on Connectors

Some wellhead and LMRP connectors require reduced pressure (500-800 psi) after locking at 1,500-3,000 psi. This requires a second regulator circuit in the pod to reduce to holding pressure after the connector is locked. It may reduce lines available in the pod.

3.6.10. Open vs Closed Loop

Closed loop systems return operating fluid to the surface. This may require the system to pump return fluid back up to the rig. Otherwise, BOP closing times may increase beyond safe operating practice and regulatory requirements. The system may be designed to operate

during normal testing and non-well control procedures when closing time is not critical, and vent to the sea during well control or emergency disconnect procedures.

3.6.11. Retrievable Pods

Guidance problems can occur due to variable, strong currents

It is possible to use retrievable pods, but may not be always practical due to the size of the pods and possible damage to both pods and the marine riser during retrieval and running. Guidance problems can be significant in deepwater with variable and strong currents. Retrieveable pods may be more feasible where drillpipe can be used as the retrieval method and the rig can be rotated to keep the pod away from the riser. This requires wet mate connectors for MUX umbilical and any auxiliary electrical functions such as riser angle and azimuth, TV cameras, lights, etc.

3.6.12. Single Point Failures

Redundancy prevents single point failures

Single point sources of failure are avoided by providing redundancy such as two pods, dual uninterruptible surface power supplies, dual subsea electronics in each pod, multiple communications paths, multiple surface control panels, dual cable reels, and subsea accumulators to back up riser hydraulic conduit lines.

With a two pod system the first true single point of failure would be the shuttle valve on the BOP stack function.

3.6.13. Pressure and Temperature Gauges

Transducers are available for installation on the BOP Stack that can furnish input to the MUX system for transmittal to the surface. These require wet mate electrical connector when transducers are mounted on lower section of BOP stack.

Transducers can be mounted in the C&K lines in the LMRP with the tradeoff of no wet mate electrical connector. However, data may be less useful. If sensors are mounted

in the LMRP C&K lines, temperatures are largely isolated from the BOP and become unrepresentative unless fluid is moving through the C&K line. Pressure measurements are useful if C&K valves are open (i. e., during well control), but not useful during normal operations with the valves closed (e. g., to assess riser cleaning).

Breakaway connections from the LMRP MUX to BOP located sensors

Another alternative is to provide breakaway connections from the LMRP MUX to BOP located sensors. Since disconnection of the LMRP and hence breakaway is a relatively unusual event, this would provide BOP measurements for most occasions

3.6.14. How Bottles Are Manifolded

Surface- Should be manifolded so that no greater than 25% need be shut off for maintenance of accumulators.

Subsea- Consideration can be given for subsea bottles to be manifolded for specific requirements, including the following:

- Stack accumulators
- Shear accumulators
- Acoustic accumulators
- Deadman accumulators

Due to space requirements and limitations it may necessary to have multiple manifolds for each function.

Manifolding is important in relation to back up systems

Manifolding is particularly important when considering back up systems, such as automatic shear and seal systems and also acoustic systems.

3.6.15. Back-up Systems

The following sections describe the features and operation of several back-up systems.

Back-up systems:
- **Electro-hydraulic**
- **Acoustic**

3.6.15.1. Electro-hydraulic

- Direct electric pilot, no logic involved.
- Uses dedicated wires in MUX umbilical wired through to the pod solenoid valves.
- Operates emergency functions such as shear ram emergency disconnect.
- Requires integrity of MUX umbilical cable, surface wiring, and control panel.
- Requires integrity of surface and/or stack accumulator supply and hydraulic flow through the pod.

3.6.15.2. Acoustic back-up system

- Dedicated system includes subsea accumulators, battery packs, electro-hydraulic control module, acoustic communication transponders, fixed and portable surface control and communications systems.
- Usually operates seven functions to include pipe ram, shear ram, C/K valves, LMRP and stack connector release.
- Does not depend on integrity of normal BOP stack control system nor marine riser or MUX umbilical.
- Accumulators require charging from normal BOP stack control system (however, any pressure loss is protected by check valves if normal BOP stack control system fails).
- It must be noted that many contractors and operators still do not consider acoustic back up systems reliable.

3.7. Preventive Maintenance Considerations

3.7.1. Summary

Maintenance for a subsea stack and its components is critical to a safe operation. Considerations for maintenance provided in the tables below are for general reference only. Refer to the original equipment manufacturer's recommendations as the first source of guidance regarding preventative maintenance.

3.7.2. Stack

3.7.2.1. BOP

BOP Maintenance Interval	Task
For each well	– Open every ram cavity and visually inspect conditions of bores, ram packers, and top seals. – Test hydraulics. – Perform function & wellbore tests based on MMS requirements.
Annually	Inspect ram block to ram cavity clearances to ensure that they are within published manufacturing tolerances.
Every 3 – 5 years	Disassemble, dimensionalize, repair as needed, and renew all rubber goods based on manufacturer's recommended specifications.

Table 3-2 Preventive maintenance: BOP.

3.7.2.2. Annular

Annular Maintenance Interval	Task
For each well	– Visually inspect annular elements. – Test hydraulics. – Perform function and well bore tests based on MMS requirements. – Drift test to insure ability to pass fall bore tool.
Every 3 – 5 years	Disassemble, dimensionalize, repair as needed, and renew all rubber goods based on manufacturer's recommended specifications.

Table 3-3 Preventive maintenance: annular.

3.7.2.3. Flex joint/ball joint

Flex Joint/Ball Joint Maintenance Interval	**Task**
For each well	Visually inspect flex joint/ball joint for key seat damage.
Every 3 – 5 years	Disassemble, dimensionalize, repair as needed, and renew all rubber goods based on manufacturer's recommended specifications.

Table 3-4 Preventive maintenance: flex joint/ball joint.

3.7.2.4. Connectors

Connectors Maintenance Interval	**Task**
For each well	– Clean and inspect seal surfaces and lubricate. – Test hydraulics. – Perform function and well bore tests based cc MMS requirements.
Every 3 – 5 years	Disassemble, dimensionalize, repair as needed, and renew all rubber goods based on manufacturer's recommended specifications.
If packages are broken	– Clean/Inspect both connector and mandrel. – Install new gasket.

Table 3-5 Preventive maintenance: connectors.

3.7.2.5. Pods

Pods Maintenance Interval	**Task**
For each well	Perform function tests based on MMS requirements.
Annually	All pod valves, shuttle valves, and regulators should be torn down, inspected, rebuilt/renewed with new/reworked components

Table 3-6 Preventive maintenance: pods.

3.7.2.6. Wing Valves

Wing Valves Maintenance Interval	**Task**
For each well	– Perform function and wellbore tests based on MMS requirements.
Annually	– Tear down, inspect, rebuild/renew with new/reworked components – Motion compensation

Table 3-7 Preventive maintenance: wing valves.

3.7.2.7. Tensioners

Tensioners Maintenance Interval	Task
For each well	– Visually inspect. – Slip, cut, and reterminate based on wire rope manufacturer's recommendation.
Quarterly	Inspect fluid and send sample for testing.

Table 3-8 Preventive maintenance: tensioners.

3.7.2.8. Drillstring - Compensator

Drillstring - Compensator Maintenance Interval	Task
For each well	Visually inspect.
Quarterly	Inspect fluid and send sample for testing.

Table 3-9 Preventive maintenance: drillstring - compensator.

3.7.2.9. Riser

Riser Maintenance Interval	Task
For each well	– Visually inspect each joint during pickup and laydown, paying attention to the bouyancy material. – Pressure test while running.
Every 3 – 5 years	Non Destructive Examination (NDE), dimensional inspection, and repair as needed based on manufacturer's recommendations

Table 3-10 Preventive maintenance: riser.

It should be remembered that the above guidelines are considered minimums and more frequent maintenance may be necessary.

BOP maintenance time on DP rigs is greatly reduced

On DP rigs, time for BOP maintenance can be greatly reduced due to the elimination of the requirement to pull and run anchors. It is imperative that the operator give the contractor a sufficient amount of time between wells to maintain the stack, even if other operations are temporarily suspended.

3.8. Riser Recoil Considerations

3.8.1. Summary

Deepwater locations require tremendous top tensions due to the length of the riser, mud weights, and requirements of angle at the lower ball joint. In a 6,000 ft water depth location, a 21" marine riser system can have a mass of 3,000,000 lbs and a wet weight of 300,000 lbs.

Top tensions

These tremendous top tensions pose a unique problem for a dynamically positioned drilling rig. In the event of an unplanned disconnect, the huge amount of energy/force stored in the riser and the tensioning system is almost instantly converted to an acceleration according to the elementary equation a = F/m, where

a = acceleration
F = force
m = mass

Clearly, some method is required to dissipate this energy prior to the contact of the riser telescoping joint with the rotary table. If the energy is not sufficiently dissipated, the result could range from minor damage to the rotary table and substructure to major damage to rotary and substructure and loss of the riser.

3.8.2. Unplanned Disconnect

Three types of energy to be dissipated during an unplanned disconnect

The three types of energy that must be dissipated during an unplanned disconnect are as follows:

- the energy in the tensioner cylinders
- the strain energy in the tensioner cables
- the strain energy in the marine riser itself

In 6,000 ft of water, the stretch in a 21" x 5/8" marine riser can be up to 5 ft. This stored energy is converted to kinetic energy at the point of release and accelerates the riser upwards independently of the tensioning system.

Slack in tensioning cables may cause large pressure peaks in tensioner cylinders

Another concern related to the tensioner system in this situation is the possibility of the riser not being captured on the first attempt by the riser hang-off system. As the ship heaves in high sea conditions, and the riser gets out of sync with the ship, there is a likelihood of some slack in the tensioning cables. This slack can cause very large pressure peaks in the tensioner cylinders.

Following is an outline for consideration when designing a riser recoil system:

3.8.3. Reasons for Riser Recoil System

- **Safety** - Slip joint slams closed and drives diverter/rotary upward
- **Minimize damage to BOP** - Prevent LMRP from beating top of BOP stack in the event of an emergency disconnect
- **Minimize damage to riser components**

3.8.4. Types of Systems

- **Passive Manual** -- Operator must manually set all tensioners and Air pressure valve (APV) to be used. Activates only from emergency disconnect sequencing (EDS) signal.
- **Passive Automatic** -- APV settings are automatically figured based on manual input of mud weight, water depth, and automatic sea state sensing. Activates only from EDS signal.
- **Active** - Manual input of mud weight and water depth. System activates automatically under all riser/LMRP separations (currently under development).

3.8.5. Other Considerations

- Water depth: the deeper the water, the more need for this system
- Mud weight
  - Friction forces down in main tube
  - Propulsion forces up from mud exiting riser
- String weight
  - LMRP weight and cross sectional area
  - Size and weight of riser
  - Number of joints buoyed
- Total tensioning capacity
  - Number and size of tensioners
- Slip joint
  - Automatic latching device to prevent "bobbing" effect
  - Stroke length
  - Set at midpoint or above to allow for vessel excursions
- Riser capture/hang-off

Designing a proper riser recoil dampening system and hang-off system is complex and difficult. Consideration should be given to having outside experts involved in the design and testing of the system

Full scale test of riser recoil dampening system under controlled conditions is strongly recommended

When a new system is deployed, consideration should be given to a full scale test of the system under controlled conditions in order to ascertain the operability of the system.

3.9. ROV Interventions Considerations

3.9.1. Summary

The ROV system can be used to carry out visual inspections of the seafloor BOP, the riser, and the rig. In addition it performs the following functions:

ROV Area of Inspection	Features
Seafloor	• Topography • Obstructions • Geologic conditions • Recovery of dropped object
BOP	• Overall inspection • Leveiness (bullseye) • Valve override • Emergency disconnect operations • Component replacement (AX/VX rings) • DP beacons • Status indicators
Riser	• General inspection • Support for replacement of individual BOP control hoses where appropriate
Rig	• Inspection of hull, thrusters, intakes, etc. • Removal of debris from thruster, cooling intakes, etc.

Table 3-11 ROV inspection functions.

3.9.2. Equipment Modifications to Optimize ROV Support Capabilities

- Proper accessibility to required locations
- Proper docking/handholds at specific locations
- Proper marking and identification criteria for low visibility operations (see API 17H and Deepstar)
- Proper design and orientation of the selected override functions
- Reliability of AX/VX ring release and replacement

3.9.3. Common BOP Override Functions

LMRP and Wellhead Connector Unlatch - both can and have been done.

All Stabs Retract - This is an LMRP function in which several functions could operate at once. However, due to the volume needed for each function, they release and retract in a proper sequence. The functions are choke and kill, mini connectors unlatch, and acoustic stab retract.

LMRP and Wellhead Ring Release - Release and/or lock the AX/VX ring on both LMRP or wellhead connectors. Depending on the connector this can be a dual function. Some ring release rams have a spring failsafe lock.

Methanol Injection - There are a half dozen ports around the connector base. With appropriate piping the ROV can inject methanol into these ports to lower the chance of freeze up.

Pipe Rams and Shear Rams - Open and/or close from one to all three of these rams. Also install an all open function where all rams can be opened at the same time or individually.

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4.0 EMERGENCY RESPONSE

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Chapter 4. Emergency Response

Emergency Response Subcommittee
Don Shackelford (Chairman) – Halliburton Company
David Barnett – Wild Well Control
Larry Flak – Boots and Coots IWC
A. J. Heikamp – Marine Spill Response Corporation
John Knowlton – Diamond Offshore Drilling Company
Greg Navarre – Global Marine Drilling Company
Steve Pulkowski – Murphy E&P Company
Todd Regalado – Wild Well Control
Curtis Weddle – Cherokee Engineering

BCP	Blowout contingency plan
BHA	Bottomhole assembly
BTF	Blowout task force
BU	Business unit
DGPS	Differential global positioning satellite
DOD	Department of Defense
DP	Dynamically positioned
E&P	Exploration and production
GOM	Gulf of Mexico
GOR	Gas/oil ratio
GPS	Global positioning satellite
IR	Infrared
LMRP	Lower marine riser package
MMS	Minerals Management Service
MODU	Mobile offshore drilling unit
MWD	Measurement while drilling
PR	Public relations
ROV	Remotely operated vehicle
SOWM	Spectral Ocean Wave Model

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4.1. Introduction to Emergency Response

4.1.1. Objective

In this section we propose to give the reader background information necessary to:

Protection priorities:
- **People**
- **Environment**
- **Physical plant**
- **Mineral resource**

- Generate an emergency response plan for deepwater drilling
- Understand the success factors for emergency response in well planning and relief well drilling
- Understand the success factors in a dynamic well kill operation
- Understand the requirements and techniques of spill control
- Evaluate speculative ideas on vertical intervention for well control

Of the many tasks involved in deepwater operations, prevention of well control problems requires all out effort. The early establishment and testing of a well-orchestrated emergency response must be given equal attention in the event well control problems arise.

Early establishment and testing of a well-orchestrated emergency response

It is important to clearly establish the priorities of emergency response well ahead of any potential event. A focus on problem solving should take precedence over philosophical debate on big picture issues. A generally accepted ranking of priorities is as follows:

1. Protection of health and safety of people
2. Protection of the environment
3. Protection of the physical plant for source control
4. Protection of the mineral resource

Risk assessment

Risk identification is only the first step taken to accomplish the goal of risk management. This is the process of generating and execution of a plan of action to move identified risks from high risk and low manageability to the opposite sides of the risk identification matrix (See Figure 4-1 below).

Risks may be general or well/operation specific. One conclusion in risk identification and management may be the decision not to undertake the operation.

Overreaction and de-escalation vs deliberate response and possible lost time

Often operators and contractors make it a practice to overreact and then de-escalate their response rather than take a slower, more deliberate response and then risk having to to make up for lost ground or errors.

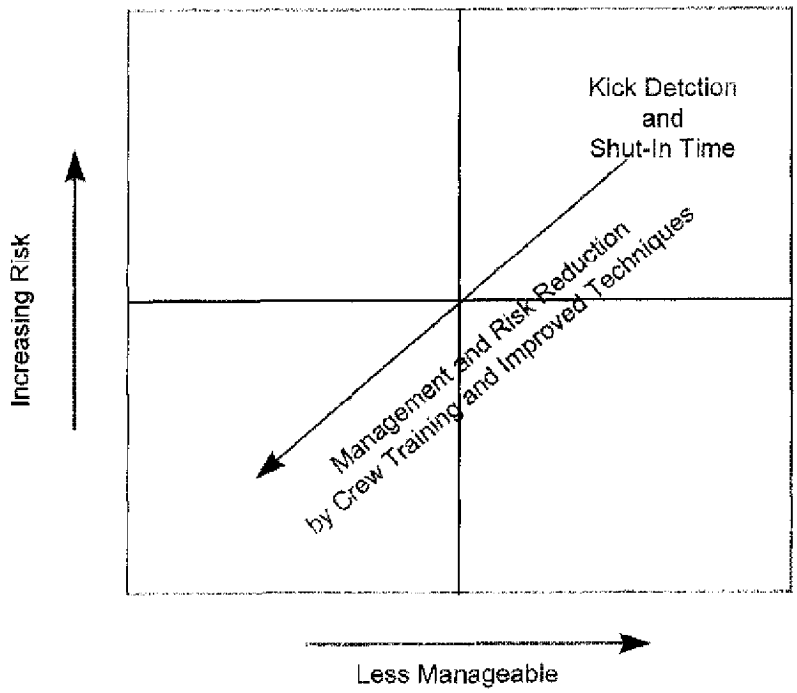

Figure 4-1 Risk Identification Matrix

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4.1.2. Levels of Well Control Emergency Response

For clarity of communication and organization the severity of well control incidents is often broken into three categories:

Level 1 Response	Level 2 Response	Level 3 Response
Least Severe	More Severe	Most Severe
Kick control	Underground blowout	Loss of control of the well at the seafloor or surface

Each level of response should have its own appropriate sequence of pre-planned responses and resources assigned to it. A suggested outline of materials and responses for each of the three levels of emergency response is presented in Emergency Response Plans (4.2).

4.1.3. Purpose and Value of Emergency Response Drills

Well-conducted emergency response drills provide significant value

Emergency response drills are sometimes viewed as dramatic play-acting. However, a well-conducted emergency response drill provides significant value. The elements and participants necessary for a successful drill require careful consideration.

Emergency response drills provide the following benefits to the organization:

- Test assumptions about readiness
- Confirm that communications networks and procedures are working and current
- Indoctrinate new staff to procedures
- Focus thinking on non-routine problems
- Clarify plans and intentions to regulatory authorities
- Demonstrate competence
- Guide improvements to prevention and emergency response

These benefits are discussed further below.

4.1.3.1. Testing assumptions about readiness

We often presume we have fit-for-purpose plans in place and that all of the parties involved in plan execution are aware of the conditions and needs related to each plan. However, conditions, needs and people change with such frequency that yesterday's plan may be forgotten, unknown or outdated.

Conduct emergency response drills annually or coincident with major changes

Testing the plan on a periodic basis provides valuable adjustments in approach to emergency response. Emergency response drills should be conducted annually or coincident with major changes in the operation, regulatory expectations or personnel.

4.1.3.2. Operational communications networks and procedures

Accurate phone and fax numbers

The ability to act swiftly and surely depends on access to accurate phone numbers, fax numbers and other relevant communication channels. Maintenance and testing of the emergency response plan manages the risk of failure in communications down to a more acceptable level.

4.1.3.3. Indoctrination for new staff

An emergency response plan may be a large encompassing document. In the normal course of busy operations the focus is on the crisis of the day, and may not consider the plan which may have prevented the incident, or which can help mitigate the problem.

The $10 bill test

A $10 bill was placed in what should have been a frequently used reference manual in the library. Six months later it was still there, perhaps due to honesty, but more likely due to inattention. If there is not a concerted effort to review plans for coping with non-routine events, those plans may be unlearned or forgotten.

4.1.3.4. Focus on non-routine problems

The competent and fortunate are not likely to experience enough crises to develop expertise in handling high risk events. Coping with a serious well control problem can involve managing a number of difficulties, including the following:

A properly planned and executed drill provides practice for non-routine tasks

- Attempting to diagnose problems based on excited, conflicting and baffling reports
- Meeting demands that everything and everyone get 100% attention immediately
- Prioritizing and delegating tasks

A properly planned and executed drill can provide some practice for a task that demands expertise many will never develop experience in.

4.1.3.5. Clarifying plans and intentions to regulatory authorities

Involve both operators and authorities in drills

Conflicts in expectations of performance and actions need to be settled before any crisis. Disagreements may arise during an emergency, but disagreements about primary objectives, jurisdictions and methods can be minimized beforehand by the use of drills involving both operators and authorities.

4.1.3.6. Demonstrating and enhancing competence

Assurance to regulators, shareholders, public sector

The actions of the operator in a drill can provide assurance to regulators, shareholders and the public sector that the industry is competent to perform as required.

4.1.3.7. Improving prevention measures and emergency response

Accommodating change

Because conditions change, the plan must accommodate change. Furthermore, techniques and technology improve. Emergency response drills and a follow-up debriefing identify the need for change and improvement.

4.1.4. Features of a Proper Emergency Response Drill

Preparation time

A well-conducted emergency response drill may initially involve several man months of preparation by staff and advisors experienced in planning and conducting them. The drill should have the following characteristics:

Requirements	Comments
Involve all staff, contractors, and regulatory agencies named in the response plan who would be expected to respond in a real emergency	• Include operator and contractor decision-makers who provide procedures and plans for the emergency response
Test the information system for upward communication to management, the media, and the public.	• Hold realistic press conferences and interviews with pointed and probing questions
Take place in a time-compressed, realistic scenario	• Compress the drill and model actions of the first 12 to 24 hours within less than 6 hours of drill time
Test all communications links	• Use all contacts and communications tools named in the Emergency Response Plan
Involve significant debriefing, feedback, and follow-up action to correct problems identified.	• Deploy observers with experience in planning, conducting, monitoring and close out of drills

Table 4- 1 Features of a well-planned emergency response drill.

4.1.4.1. All personnel, contractors and agencies

The drill should involve operator and contractor staff responsible for decision making and providing procedures and plans for the emergency response.

Representatives from the following groups should be aware of their roles in an emergency response drill:

Administrative	• Management • Media Relations • Human Resources • Accounting and Purchasing
Regulatory authorities	• US Coast Guard • Minerals & Management Services (MMS) • State/Local fish and game • Local government (shore-based) • State government
Spill control	• Operator environmental and regulatory departments • Spill control contractor
Source control	• Operator drilling management and engineering • Contractor rig management • Well control contractor • Geologic and reservoir advisors, in the event facilities are involved • Facilities and production operations and engineering groups

Table 4- 2 Recommended participants in emergency response drill.

4.1.4.2. Communication to management, media and public

Quality information in the right quantity for management and the media

The public will expect accurate and timely information. Conflicting information will need to be corrected or clarified and rumors refuted with fact. Realistic press conferences and interviews with pointed and probing questions should be a part of the emergency response drill. When those responsible for supplying information are consumed with the operation, the process of providing quality information in the right quantity up to management and the media is one of the most difficult challenges facing the emergency response organization.

4.1.4.3. Time compressed realistic scenario

Realistic tension designed into scenario

Experts who will not be emergency responders should generate a realistic scenario. They should also participate in the drill to update the scenario as conditions change and in response to actions taken during the drill. The drill should

be time compressed and model actions of about the first 12 to 24 hours within less than 6 hours of drill time. This will challenge the organization to move quickly and confidently and to add a dimension of realistic tension to the process.

4.1.4.4. Testing communications links

All contacts and communications tools contained in the Emergency Response Plan should be called and tested.

4.1.4.5. Debriefing, feedback and follow-up

Dedicated observers to monitor drill

In initial drills as much time should be dedicated to the follow-up as was spent in preparation for the drill. To do this requires dedicated observers with experience in planning, conducting, monitoring and close out of drills.

4.2. Emergency Response Plans

4.2.1. Blowout Contingency Planning

Consequences of a sustained blowout in deepwater

Well control events associated with deepwater drilling, production and workover activities present unique technical and logistical challenges to the operator and service company personnel.

The consequences which result from a sustained blowout in a deepwater environment will be far-reaching and could, conceivably, have a lasting impact on public perception.

Environmental groups, regulatory agencies, and industry commitment

History has shown that environmental groups and regulatory agencies are quick to make critical evaluations of the industry's commitment and capability to mitigate the damage associated with catastrophic events. Therefore, the identification of potential hazards and the development of a systematic response have rightfully become an essential element in sound business practice.

The methodology associated with this hazard identification and response strategy formulation is often referred to as the Blowout Contingency Plan (BCP).

The following topics will be discussed in this chapter:

- Organizational aspects of the BCP
- Well specific BCP topics

4.2.2. Organizational Aspects of the Blowout Contingency Plan (BCP)

Complex technical and logistical aspects

An effective, coordinated response to any emergency requires a pre-determined organizational structure. This is especially true with regard to deepwater blowouts since the technical and logistical aspects are among the most complex in the industry.

The key to a sound, effective BCP is to designate *and properly organize* a team of individuals with the right combination of technical and operational capabilities.

Organized team with necessary technical and operational capabilities

There have been many instances where blowout response and intervention were impeded due to a lack of leadership and adequate organization. These difficulties have manifested themselves even though the group responding to the incident had a vast amount of technical and operational experience.

Leadership

There is no single organizational scheme that is appropriate for all operators. Each company must make an evaluation of their level of experience, internal resources, corporate organization and operating philosophy in order to determine the best approach to managing a major deepwater blowout.

District or business unit evaluations

An evaluation of each district or business unit's (BU) ability to adequately manage a crisis is inherent in this process. This means looking closely at the resources and capabilities of each BU.

- Can the BU provide sufficient personnel to manage the crisis and carry on with other business functions?
- How will the BU handle the large capital outlays that are often required?
- Does a particular BU have personnel with the experience and operational/technical background to make the decisions and implement the solution?

Corporate support

These BU-specific evaluations often result in a scheme for specific corporate support of the BUs during a crisis. The extent and nature of this corporate support will be dependent upon the organizational framework and operating philosophy of the operator.

A decision tree approach to such an evaluation is illustrated in Figure 4-2 below.

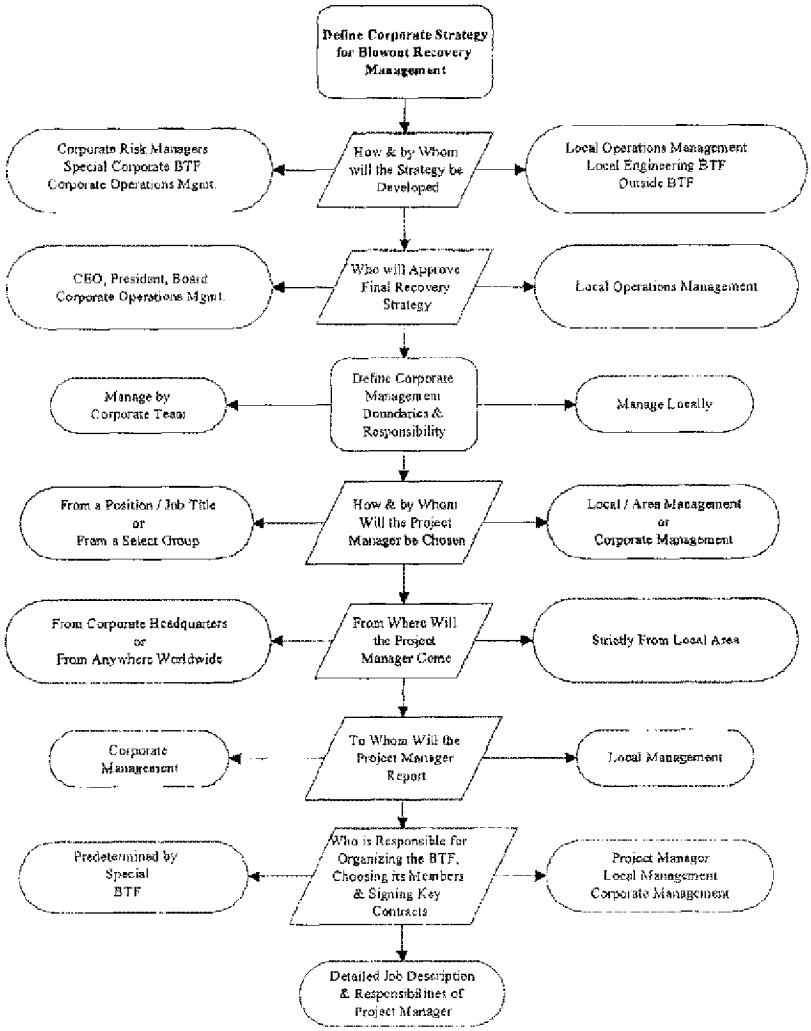

Figure 4-2 Corporate strategy decision tree for blowout recovery management.

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Experience has shown that the BCP is most effective when it is linked to an overall plan to respond to emergencies of all types (i.e., oil spills, natural disasters, business interruption, terrorism, civil unrest, etc.).

Effective BCP is part of overall emergency response plan

There are many reasons for developing the BCP as a subset of a more comprehensive crisis management plan. These include:

- Standardized format for the initial response to all emergencies
- Decrease duplication of effort (many crises require similar support from Public Relations, Legal and Finance organizations)
- Coordination of simultaneous emergency response and intervention operations (i.e., blowout intervention and spill response)

The group of personnel charged with the management of the blowout recovery is referred to by many names. Examples include Emergency Response Team (ERT), Emergency Task Force (ETF), and Blowout Task Force (BTF), to name a few.

Naming the blowout recovery group

The name designated within a given operator's organization should be chosen to be consistent with other names specified in other emergency response plans. For the purposes of this document, this group of people will be referred to as the Blowout Task Force (BTF).

4.2.3. The Blowout Task Force (BTF)

The blowout task force (BTF) must be well organized and adequately staffed with operator and service company personnel who are capable of performing the following tasks:

- Analyzing the technical, operational and safety-related aspects of the situation
- Making proper, informed decisions and formulating precise plans
- Implementing the intervention plans in the best possible manner
- Formulating alternative (contingency) plans based on experience and available information
- Handling the ancillary aspects of the crisis (public relations, legal, financial, liaison, etc.)

Blowouts do not always have a straightforward solution. There are many instances where precise plans can not be formulated until certain information is obtained. Thus, it is important that the BTF be capable of formulating feasible strategies based on experience and judgment.

Strategies based on adequate information

When adequate information is obtained, then the most viable solution can be implemented without delay.

Adequate experience allows the BTF to constantly monitor the intervention and identify possible problems. Alternative plans can be developed in case the situation changes and can be implemented with minimum delay.

Direct intervention

The organizational structure of the BTF for a major deepwater blowout should provide for the management of direct intervention activities and simultaneous relief well operations (in addition to the other non-operational duties).

If direct intervention is not feasible, the BTF complexity can be reduced accordingly. The BTF organization will vary from one operator to the next and, in some cases, from one BU to another within a particular company. The figure below illustrates a generalized organizational scheme for a BTF designed to manage a deepwater blowout.

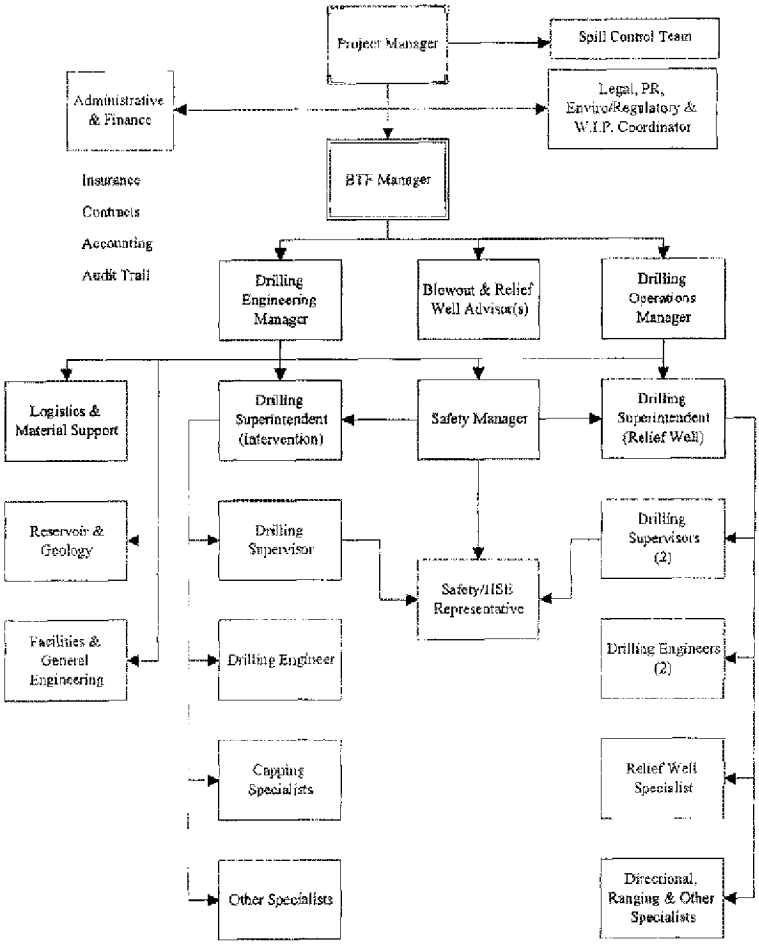

Figure 4-3 Generalized organizational scheme for a deepwater Blowout Task Force (BTF).

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4.2.4. Well Specific Blowout Contigency Plans (BCPs)

The preceding sections discuss the organization of personnel and other resources designed to properly manage a major deepwater blowout. Critical operations such as drilling, production and workover activities in deepwater often justify the development of well specific BCPs.

Well specific BCP: Concise, accessible reference

The well specific BCP is, in effect, an addendum to the overall, general BCP. It should be developed in such a way that it provides a ready information source to the blowout task force (BTF). While a great deal of the necessary information is contained in the drilling program and other documents, the well specific BCP is designed to provide a concise reference that can be quickly accessed during a crisis.

The information that is typically contained in the well specific BCP is broadly separated into two categories:

- Well and reservoir information
- Available resources

Supporting documents should be clearly identified and referenced.

4.2.4.1. Well information

The most helpful information during a blowout is that which allows the BTF to evaluate and implement the possible control solutions. This includes the information that is required to analyze options for surface intervention and relief well design/implementation.

Examples of well information useful for evaluating and implementing possible control solutions include:

Information needed to develop well control solutions

Information Type	Details
Rig and/or structure drawings **Detailed drawings of wellhead, BOP system** **Depth reference system & units**	
Azimuth reference system	• Example data: UTM, true north, local grid, grid convergence
Surveys on relevant well(s)	If available include: • well name/number • date of survey • surface tie-in coordinates • survey interval • survey type • survey company • surveyor's name • grid conversion • magnetic declination conversion • running gear configuration • magnetic spacing • BHA used • borehole temperature • tool face data • QA/QC information on the survey data (e.g., service company uncertainty model, calibration data, running procedures, surveyor's notes, overlapped surveys, etc.)
Surface map showing rig/structure site relative to:	• debris • pipelines • water depths • seabed characteristics • other seabed hazards • shipping lanes • potential relief well surface locations • adjacent structures • and other subsea hazards within one mile or the anchor pattern of the relief well rig located one mile from the well

Continued on next page

Information for well specific BCP, continued

Surface map (plan view) of the rig/structure showing:	• average prevailing winds • waves and sea currents
Surface map showing:	• latest seismic coverage to include any subsurface hazards (e.g., shallow gas, palaeochannels, faults, etc.)
Wellbore schematic showing (as applicable):	• casing design • valves • cement tops • nipples • packers • plugs • perforations • fracture gradients
Geological stratigraphic cross-section showing:	• pore pressure • fracture gradients • overburden and temperature profile (note any potential drilling hazards)
Reservoir and reservoir fluid properties	• permeability • productivity index • static reservoir pressure & temperature • GOR • reservoir extent • molecular composition of reservoir fluids

Table 4- 3 Well information useful for evaluating and implementing possible control situations

4.2.4.2. Available resources

The well specific BCP allows for a more precise determination of the equipment and personnel resources that will be utilized in case of a blowout.

Rapid mobilization

Equipment/services resources within the region

Certain individuals within the business unit (BU) organization and participating service companies can be chosen for specific functions on the BTF. Equal importance should be placed on evaluating the equipment/services resources within the region and planning for rapid mobilization.

Detailed evaluation of locally available equipment and services

The equipment and services likely to be required in the event of a major deepwater blowout will not vary significantly from one well to the next. However, the availability and logistical aspects of mobilizing the necessary equipment could be vastly different.

The well specific BCP development process should include a detailed evaluation of the locally available equipment and services.

Identify, locate, and negotiate for specialized well control equipment in advance

Those services which are not specified in the drilling program or that might need to be supplemented by additional contractors should receive particular attention. Agreements should be negotiated for the provision of all equipment and services for which no standing contract is in place.

The selection of such equipment and services may require a thorough evaluation in order to determine which is most suitable in terms of location, capabilities, price and other factors.

A general list of equipment and services that should be considered includes:

Relief well

Specialized and supplemental equipment

- Well control, well control engineering and relief well engineering services
- Relief well drilling rig (and supplemental riser/BOP equipment)
- Wellhead equipment (relief well)
- Ranging services (relief well)
- Specialized well control equipment (surface and subsea)
- Casing & cementing equipment
- ROV equipment
- Firefighting equipment (pumps, vessels, etc.)
- Seismic services
- Anchor handling vessels
- High pressure & low pressure pumping
- Additional fluid & storage

4.2.5. Sources of Flow and Source Control

Flow from a production wellhead or a BOP

It is highly probable that any subsea blowout will be flowing from either a production wellhead or a BOP. It is difficult to imagine that a riser system will remain intact or that a drilling rig associated with a riser system could remain on location in the event of a major flow.

Well-defined flow

Formation fluids may be exiting in a well defined path such as a circular cross-section. In the event of well-defined flow, ROV cameras can provide pictures which can be compared to known dimensions on the BOP stack to get a better idea of cross sectional area.

High speed photographs for flow velocity estimates

High speed photographs can be used to estimate velocity by using bubbles or other discontinuities in the flow and measuring distance traveled between successive pictures.

Multiple source flow

However, it may be that flow will be from multiple sources on a BOP such as side outlets, bonnet seals, and other hardware that may have suffered damage.

In a case like this, the wellhead may be partially or totally obscured so that inspection by ROV will not yield any method of gauging flow. In this case, experience may be the best source for an estimate of flow rate.

Effects of backpressure

Deepwater wells may commonly be capable of production rates on the order of 30,000 BOPD or 60 MMSCF/d of gas. Absolute open flow potentials would of course be greater. Production capacity of this magnitude for a land well blowout would often result in collapse and bridging of the well. However, in a deepwater blowout scenario the seawater column backpressure at the wellhead may well have the same effect as using a choke to limit production rate and prevent the collapse of the well.

The result of seawater backpressure could be a sustained flow for which the only control method would be a relief

well. One positive in this situation would the assistance in killing the flow that the backpressure would provide.

Visual inspection

In exploratory drilling there may not be reservoir information to assist in determining what well flow capability might be, so that visual inspection via ROV of the actual flow itself may yield the best source of information.

Plume development

If the well head is obscured it may be possible to get a visual inspection of plume development.

By measuring upward migration of the lighter formation fluids within the seawater and estimating or gauging the plume diameter, it is possible to calculate a volumetric flow. The gas/liquid ratio would have to be estimated and corrected for pressure imposed by the sea depth in order to get the estimated gas rate as well as the formation liquid rate.

Seafloor broach

In the event of a seafloor broach such that formation fluid is exiting some distance from the wellhead, it will probably be difficult or impossible to gauge flow as this will be obscured from mud and bottom fines which are stirred up by the flow.

However, this event may allow re-entry of the wellhead area itself so that investigation can take place from inside the flowing wellbore to determine the amount and source of damage.

4.3. Vertical Intervention

This section addresses possible means to vertically re-enter a blowing wellbore and the factors influencing surface and subsea operations.

The following general definitions will be used for water depths relative to well control:

- Conventional 1,000 ft. - 3,000 ft.
- Deepwater 3,000 ft. - 6,500 ft.
- Ultra deepwater 6,500 ft - 10,000 ft

Vertical intervention is one of several techniques proposed and defined to handle subsea blowouts by means of vessel operations at the sea surface. These operations are used to control a blowout from a floating vessel operating over the centerline of the blowout (see Figure 4-4 below).

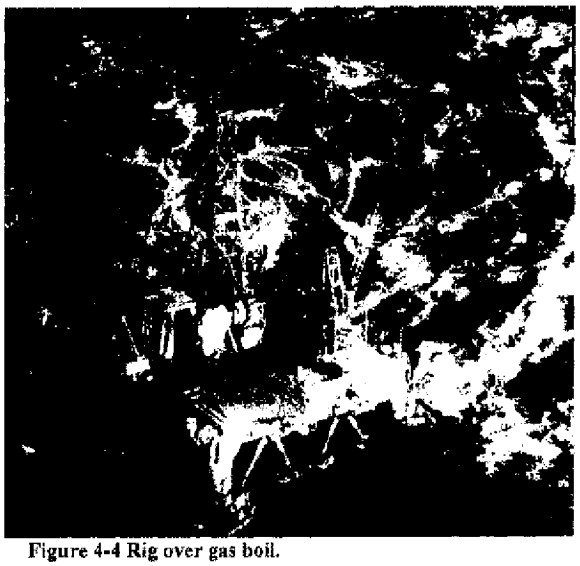

Figure 4-4 Rig over gas boil.

The fundamentals of vertical intervention from a dynamically positioned vessel and the techniques employed

to control the blowout from this position are presented in the following sections.

4.3.1. Factors Influencing Vertical Intervention Methods

Problems existing in deepwater operations may not have the same impact in shallower water depths. Likewise, many substantial problem areas in shallower water blowout control have minimum impact on deepwater events.

Problem areas for deepwater vertical intervention

Problems associated with vertical intervention techniques stem from several areas:

- Water depth
- Surface/subsurface currents
- Weather considerations
- Vessel positioning
- Equipment and compatibility
- Blowout effluent(s)
- Surface fire
- Blowout rate
- ROV capability

4.3.2. Water Depth

See also *Emergency Response, 4.6, Spill Control*

Water depth plays a role in shallow water well control operations. This is due to hydrocarbons, particularly gas, reaching surface in the form of a boil. In a deepwater well control situation with release of hydrocarbons from the well at the sea floor, it is expected that the surface release would be some distance from the rig due to dispersion and currents.

Increased water depth impacts blowouts in several areas including the following benefits (+) and hazards (-):

+ Seawater hydrostatic creates backpressure on the well that affects flow rates.
+ Seawater may act as an H_2S scrubber.
+ Disperses wellbore effluent away from well control operations.
+ May aid with relief well operations.
+ Safer working environment for personnel associated with surface operations.
– Water intrusion into the blowout plume resulting from density defects dilute effluents and increase surface boil radius. Water intrusion into gas plumes is usually substantial.
– Passive bridging is inhibited.
– Well control operations are hampered by the distances and extreme forces associated with a deepwater flow.

4.3.3. Well Control Impact of Surface/Subsurface Currents

Surface currents associated with drilling operations vary from area to area. The Gulf of Mexico (GOM) does not have the problem severity of tidal surface anomalies as seen in Southeast Asia.

Mooring and riser problems have been documented over the years due to these adverse conditions. Surface wind and wave actions can also affect the station-keeping ability of the vessel.

Subsurface currents

Subsurface currents may increase as water depths become greater. The stronger currents make vertical intervention tool selection more complex and demand stability when intersecting a blowing well.

Visibility problems

Visibility problems can also be associated with current conditions due to pollution effluent hindering ROV and vertical intervention operations.

Effects of outward radial currents

Outward radial currents associated with the boil at surface may affect mooring. It has a particularly adverse effect on ship-shape rigs. These currents are easily manageable with semi-submersible vessels if proper techniques are employed.

4.3.4. Weather Considerations

Weather forecasts are crucial in the planning stages of floating vessel blowout control. Operations hinge on good weather windows for safe working operations.

Industry utilizes three sources to obtain weather information:

- ship observations
- hindcast studies
- measurements

4.3.4.1. Ship observations

Ship observations are the initial source for weather information. They record wind, waves, current, and temperature every six (6) hours.

The information is radioed and mailed into the agency having jurisdiction over that particular area. Summarized information is put into tables for general publication. This data set is occasionally unreliable due to unreported events and overestimations.

4.3.4.2. Hindcast studies

Hindcast studies are similar to weather forecasts. They are based on past information rather that short term predictions.

The Spectral Ocean Wave Model (SOWM) is a Navy computer program developed to calculate weather conditions at designated grid points covering the northern hemisphere. These calculations are based on current and past weather data and averaged over a period of time.

4.3.4.3. Measurement

Measurement is the most reliable, but least available, means to forecast weather. Current meters, anemometers,

and wave rider buoys are utilized to predict weather patterns in various geographical locations.

Good weather window for well control operations

During sensitive phases of any well control operation, weather is a factor. Vertical intervention, relief well intercept, or crane barge operations all depend on good weather windows. If compromises are made and operations are conducted in less than desirable conditions, injuries or structural damage may result.

Weather forecasts should be plotted and amended on a daily basis during the duration of the well control operation. All vertical intervention, kill plans and/or critical operations need a clear weather window prior to initiating operations.

4.3.5. Vessel Positioning

Methods for vessel positioning

Three basic methods exist for positioning a floating vessel:

- chain
- chain/cable
- dynamic positioning (DP)

Chain or a chain/cable combination currently moors a majority of the floating drilling rigs operating in water depths up to 6,500 ft. Ultra deepwater vessels are dynamically positioned (DP).

The basic objective for position-keeping of a free-floating vessel is to maintain the drill pipe and riser in a near-vertical position over the hole.

The environmental forces generally associated with this task are wind, ocean currents, and wave action.

Wind forces

The most significant environmental force is wind. Wind varies with speed and direction on a continual basis. The data gathered from the monitoring system is input in the DP computer. These calculations utilize the shape of the vessel and the wind drag characteristics of the rig. Total forces exerted by the wind are calculated and the required power distribution is sent to the thrusters for station-keeping.

Well control operations may be suspended if vessel positioning is altered. High wind and surface currents demand stringent station keeping ability.

Acoustic-based DP systems

Thruster efficiency reduced in gas boil

Acoustic-based DP systems do not function in gas-aerated water. If a DP vessel is utilized where a gas boil is present at surface, thruster efficiency is also reduced due to the aeration of the water. Some vessels have shallow suction headers for main engine salt water cooling systems that will also be affected.

4.3.6. Equipment Availability and Equipment Compatibility

The first step after any blowout is a site evaluation. Once the initial site evaluation and rig inspection (if applicable) has been conducted, identification of useable equipment and compatibility needs to be addressed. If the BOPs or riser were lost, an equipment search may be required to locate replacements.

Extended delivery schedules affect deepwater equipment availability

Due to the high activity level, industry has extended delivery schedules that make auxiliary equipment such as ram preventers and subsurface equipment a scarce commodity. Most currently available, rental equipment may not be suitable for a deepwater event.

- Few 18.75 in., 10m, or 15m BOPs are readily available in the event of an emergency and integration with existing BOP control systems on the rig would pose additional difficulties.
- Riser availability is even scarcer, with delivery schedules reaching 24 month waiting periods.

Equipment compatibility issues need immediate attention. Manufacturers currently do not have standards for equipment compatibility. This could prove to be a major stumbling block in developing sound procedures for handling deepwater events. Items such as wellhead equipment are unique by manufacturer and can have long delivery lead times.

Primary kill guidelines: unrelated to BOPs

Proposed kill guidelines should be focused, initially, on techniques unrelated to BOP equipment on the well. This approach avoids the issues of equipment compatibility.

Secondary kill guidelines: existing or new BOPs

Secondary kill guidelines can focus on possible control techniques with existing or new BOP equipment.

4.3.7. Blowout Effluent

Flow product types affect the situation. If gas is the product, environmental impact will not be such a pressing issue as if it were oil or condensate. Pollution parameters are discussed in detail in the Section 4.6, Spill Control.

Pollution parameters

Subsea visibility may be a factor for vertical intervention. As a result, kill techniques should be developed that require little or no visibility at the mudline.

Sour fluids

Sour fluids should be considered and evaluated on a case-by-case basis. Techniques have been developed that allow safe, working operations in high sour gas concentrations.

4.3.8. Surface Fires

Fire suppression and water cooling systems

Fire at the waterline adversely affects positioning a floating vessel over the blowout for obvious reasons. Fire suppression systems could be used to minimize the heat under the rig or in the moonpool area. However, it may not be such that a fire suppression or water cooling system could be used reliably. Extinguishing the fire is almost impossible.

4.3.9. Blowout Rate

The blowout flow rate can create problems with vertical intervention at the point of entry. Stabbing kill assemblies through flow can create an additional set of problems.

Subsea plume dynamics

Knowledge of subsea plume dynamics is required to develop viable reentry procedures. Without foreplanning, reentry will be difficult.

Computer modeling will aid with estimations on where possible gas boils may break at surface due to subsurface currents and surface wind conditions. The unknown elements will serve as key points prior to any site selection for a relief well or vertical intervention rig. These systems must be developed independent of the equipment type remaining on the well.

4.3.10. ROV Capability

The remote-operating vehicle (ROV) has limited capabilities. Many are equipped with tool kits, suction dredges, etc. The three families of ROV packages currently consist of the following:

- 10-20-40 hp units;
- 75/100 hp units; and
- a third less common 150 hp unit with additional payload and thrust capability.

ROV intervention may aid in the following areas:

Typical ROV packages

- Providing visual support/video capability
- Replacing ring gaskets
- Making or breaking connections/recovering dropped objects
- Detaching/re-establishing guide wire or guide post (if applicable)
- Actuating hydraulic functions with "hot stabs"
- Underwater inspections/explosives placement
- Underwater weld repair/oxy-arc cutting

With technology changing in the deepwater arenas, ROVs have not made many significant advances to aid with floating vessel blowout control. New designs are limited to additional horsepower and larger payload capabilities.

4.3.11. Vertical Intervention Tools

Depending on the situation and BOP condition, several different tool string designs may be required for vertical intervention operations. Several considerations need to be addressed while designing the tool string for easy access into the BOP/s or wellhead assembly.

Vertical intervention tool string design

Vertical intervention tools require designs for three fundamental areas:

- Guidance re-entry systems
- Reentry tool strings
- Pipe conveyance mechanisms

Guidance design criteria are as follows:

- Universal designs regardless of equipment types on the well
- Designs for specific equipment types
- Means to handle flow-related, decentralized forces

Components for re-entry tool strings

Reentry tools strings can include the following items run individually or combined:

- Mechanical packers
- Inflatable packers
- Stingers
- Knuckle joints
- Collars or heavi-weight pipe
- Float valves and/or ported subs

4.3.11.1. Mechanical packers

Mechanical set packers may play a role in vertical intervention if access to the well can be achieved. This packer type is rigid and has two sets of slips energized by rotation.

Mechanical packer limitations

The tool has setting limitations due to size and weight criteria of casing strings. If casing has not been damaged due to abrasive flow or mechanical means, the mechanical packer may be used as a plug to stop or reduce formation fluid flow exiting from the BOPs while relief well

operations are ongoing, or damaged subsurface equipment is being repaired.

Mechanical packer setting procedures

Other limitations include setting procedures for the packer. Rotation is required which may cause damaging actions on the pipe from the seafloor to the rig. Also, the time required for the packer elements to fully expand may allow erosion of rubber elements from blowout fluids.

If the vertical intervention assembly is capable of passing through the BOPs and can be successfully set downhole, the damaged equipment on the seafloor may be retrievable, thus allowing repair and re-use.

4.3.11.2. Inflatable packers

External diameters and running diameters

Some well control operations have utilized inflatable packers for controlling wells on and offshore. Some inflatable packers can seat in large diameter sizes. However, inflatable packers have reduced differential pressure capability the more they are expanded.

May control several casing sizes

Vertical intervention methods may utilize inflatable packers to control several casing sizes. In a situation of a listing BOP, small diameter tools may have the ability to pass through the BOPs and be set in casing. Since this packer style does not have any external slip assemblies as seen on the mechanical type packers, the potential of hanging-up on ram cavities is reduced.

Setting speed

An advantage to an inflatable packer is the setting speed. It can be activated with a dropped ball, which quickly inflates the rubber. This will minimize flow erosion.

4.3.11.3. Stingers

Stinging blowing wells has been a common practice for many years. Operations in the Kuwait fires utilized this well control method to control over 225 wells. This method can be utilized on wells that do not have substantial volumes of exiting fluids.

Restricted use of stingers due to large casing sizes

For deepwater efforts, seawater hydrostatic may aid in stinging operations. Since many deepwater scenarios may involve large casing sizes, use of a stinger may be restricted due to the upward force created with the stinger in the flow path.

4.3.11.4. Knuckle joints

Knuckle joints can be utilized as part of the vertical intervention kill string. They assist in enabling passage through the BOP opening or wellhead. Strategically placed throughout the drillstring, these joints can aid with entry and allow the drillstring to move through the passageway without being hung up due to the rigid nature of the assembly.

Knuckle joints as primary bending points

Vertical intervention kill strings may have knuckle joints as a primary bending point(s) in the bottom hole assembly (BHA). Each BHA may change depending on the blowout conditions at the time of entry.

4.3.12. Vertical Intervention Scenarios

Many possible scenarios exist in which a deepwater blowout could occur. This list of scenarios is reduced substantially when practical limits are established. Also, blowouts on land and in shallower water can be reviewed to further develop the list of probable deepwater blowout scenarios.

A partial list of realistic scenarios is as follows:

- BOPs are open and remain on the stack, riser disconnected -- BOPs remaining vertical or listing.
- BOPs closed with leaks in lower flanges or valves.
- Riser and BOPs disconnected with wellhead vertical or listing
- Collapsed riser fallen to mudline
- Casing rupture blowout
- Blowout around the casing with/without cratering and with/without a listing wellhead/BOP assembly
- Blowout under a deepwater production jacket
- Satellite well blowout with flow line still intact
- Mudline blowout with the effluent at a remote distance from the wellhead.
- Blowout with settling casing
- BOP intact allowing possible ROV intervention
- Gas blowout causing difficulties in dynamic positioning

This list should be expanded and studied to allow development of detailed kill plans with contingency plans for problem areas within each scenario. However, this task is substantial and well beyond the scope of this current project. Experienced well control specialists are necessary to provide reliable plans for this type of project.

A typical blowout scenario has been developed for example purposes. For illustrative purposes, assume the following conditions exist for an uncontrolled flow of gas:

Water Depth	Formation Pressure	Flow Rate	Product	Current	Wind
4,500 ft	8,800 psi	35 mmcf/day	Gas	5 Knots	35 mph

- Disabled rig (semi-submersible) can be moved from location
- The riser has been severed or disconnected
- The well may be flowing through the BOPs, riser joint, severed riser end, and drillpipe
- BOPs are listing
- ROV tether damage

An illustration is shown in Figure 4-5 on the following page.

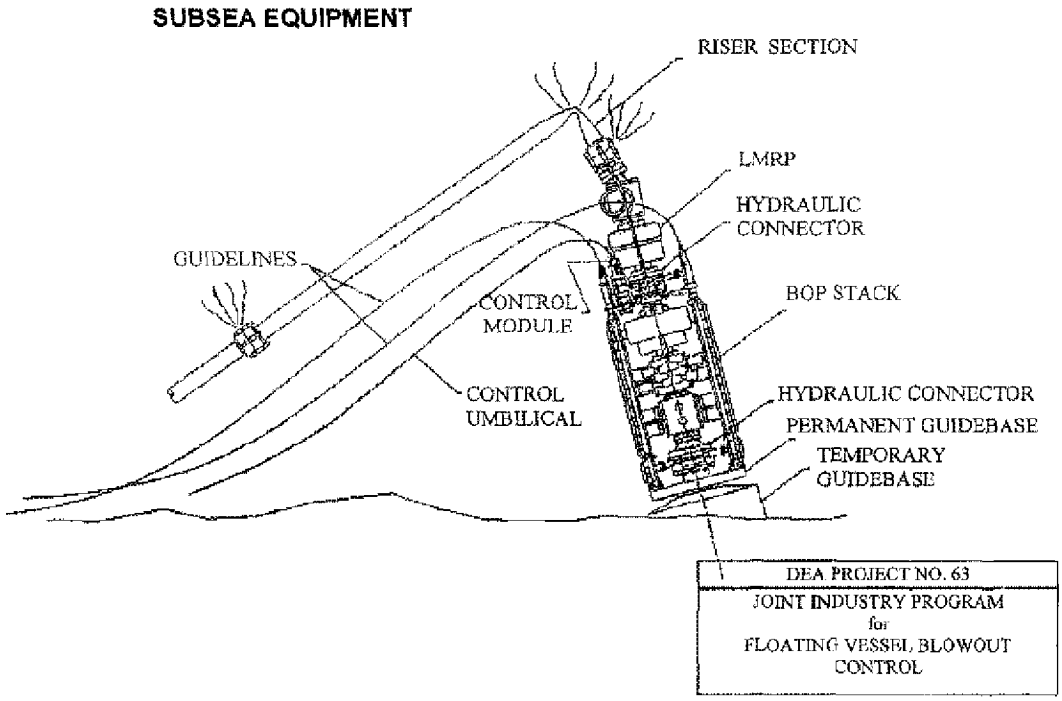

Figure 4-5 Blowout scenario: subsea equipment.

Preliminary Control Plan

This scenario will implement procedures associated with floating vessel blowout control:

Step	Action	
1	Initiate emergency response plan	
2	**Blowout Task Force**	• Initiates floating vessel control plan
3	**Subsurface Team Leader**	• mobilizes an additional dive boat with replacement ROV • mobilizes additional back up support for subsurface investigation
	Surface Team Leader	• conducts rig evaluation • assesses rig damage • mobilizes auxiliary equipment for damaged subsurface equipment
	Relief Well Team Leader	• procures relief well rig and associated equipment
	Weather & Logistics Team Leader	• addresses weather conditions for next two months • plots data
4	Ensure all auxiliary equipment pre-determined in Floating Vessel Blowout Control Plan has been mobilized	
5	Hold review meeting for all Team Leaders – chart and plot delivery schedules for auxiliary equipment	
6	Hold safety meeting with all personnel associated with well control operation	
7	Spot dive boat #1 with ROV equipment near damaged rig	
8	Begin subsurface investigation with ROVs (videotape all dives)	
9	Spot dive boat #2 near drilling location (GPS coordinates)	
10	Interpret all data from videos – record and chart all activity (blowout effluent, type, current direction, etc.)	

Table 4- 4 Example scenario: preliminary blowout control plan procedures.

At this point of the operation, the following information should have been gathered:

Surface and subsurface assessment data

Surface Assessment (Rig)

- Surface investigation of the rig shows damage to two riser tensioners (seals)
- ROV equipment damaged and non functional
- Lost upper package and +/- 2,000 ft of marine riser
- Damage to moon pool beams from riser dragging, still operable
- Lost subsea camera
- Gas boil approximately 0.50 mile from original location - no oil, no fire

Subsurface Investigation

- BOPs listing @ 5-10 degrees
- Gas traveling with currents
- Visibility good on up-current side of BOPs
- Well blowing through top of BOPs and flow has reduced on body of bottom rams
- No surface broaching is visible
- Wellhead is holding pressure
- Riser and upper package are 300 ft from BOPs and lying on seafloor with 7 sections of marine riser intact, an additional 30 joints are scattered on seafloor
- Control lines still connected to upper package

AFTER EVALUATING THE CURRENT DATA:

Step	Action
1	Repair damage on rig (all components)
2	Retrieve or replace LMRP
3	Move rig over original well
4	Make up vertical intervention tools (RTTS Packer, knuckle joints, heavy-weight drillpipe, etc)
5	Build ROV guide arms and install under moonpool
6	• Conduct ROV operations to ensure blind/shear rams and bottom pipe rams are in the open position • Survey BOPs after blind/shear and bottom pipe rams are in the open position
7	Check for increased flow after fully opening all cavities
8	Monitor well condition with subsea camera and ROV

Table 4- 5 Example scenario: post-assessment procedures.

AFTER THE WELL HAS STABILIZED:

Step	Action
1	Secure vertical intervention string to guidelines while RIH
2	RIH with vertical intervention string
3	Survey BOP condition prior to initial stab attempt
4	Attempt to stab assembly If tool string hangs up, use ROV guide arms to move string (See Figures 4-6 and 4-7 below)
5	Lower kill assembly to desired depth and set packer to stop flow
6	Back off from packer and POOH
7	Prepare to run modified connector to disconnect and release damaged BOPs from wellhead

Table 4- 6 Example scenario: procedures after well is stabilized.

Illustrations of re-entry procedures are shown in Figures 4-6 and 4-7 on the following pages.

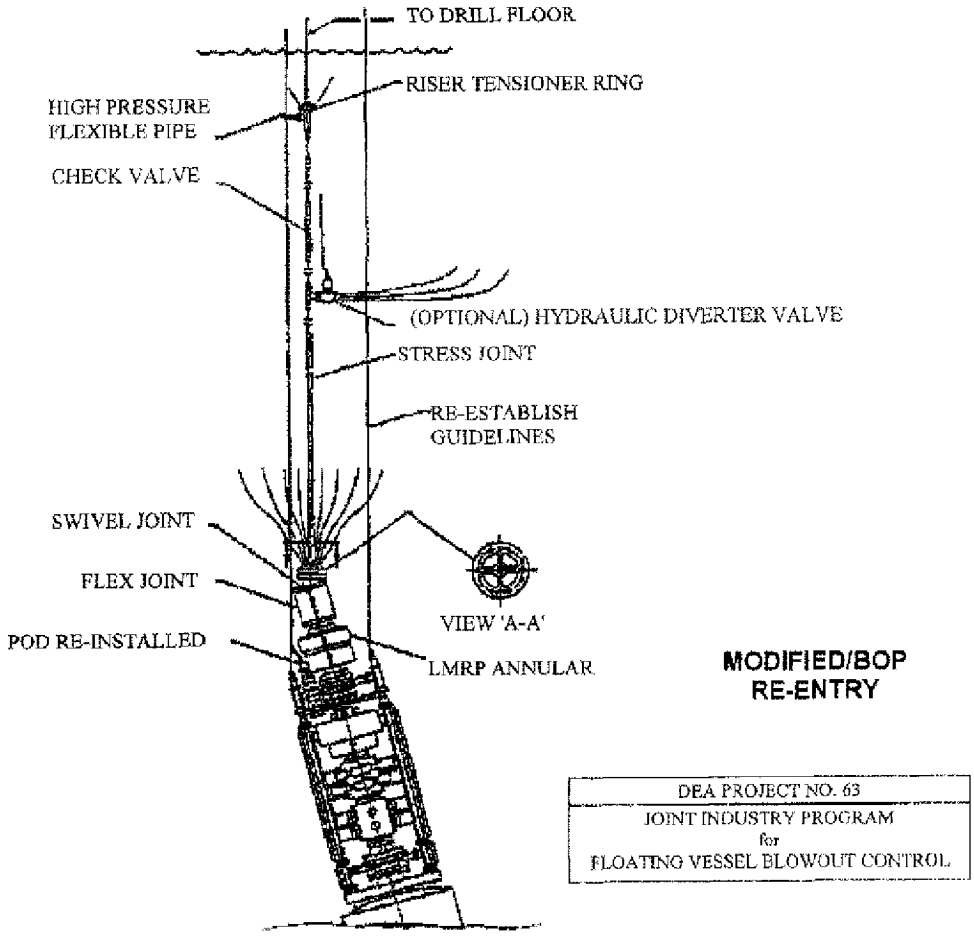

Figure 4-6 Blowout scenario: modified BOP re-entry.

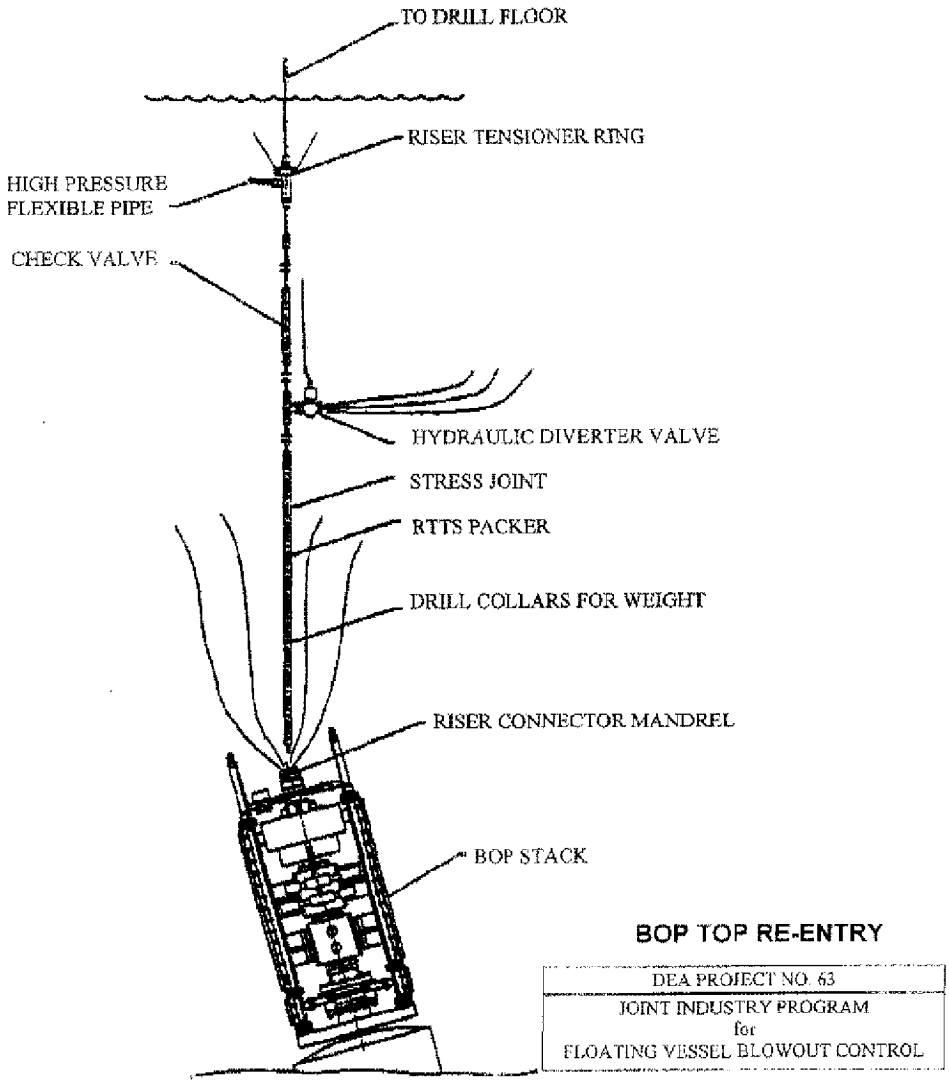

Figure 4-7 Blowout scenario: BOP top re-entry.

TO DISCONNECT AND RELEASE DAMAGED BOPS FROM THE WELLHEAD:

Step	Action
1	Disconnect BOPs, monitor well, pull damaged BOPs
2	Repair damaged BOPs and test
3	RIH with BOPs and marine riser
4	Land BOPs and test
5	RIH to displace seawater with kill fluid
6	Sting into packer and release, circulate gas from wellbore

Table 4- 7 Example scenario: procedures to disconnect and release damaged BOPs.

This generic scenario shows basic steps for controlling the situation. Many additional operations will be required. Several attempts may be required during the course of any vertical intervention method.

4.4. Rig Positioning and Surveying for Relief Wells

Relief well positioning

Any relief well drilled to intercept a deepwater blowout will be impacted by possible surface and subsurface positional uncertainty of the blowing deepwater well. The subsurface wellbore uncertainty concerns are not any different than shallow water or land wells.

Surface and subsurface positional uncertainty

The greatest difference lies in positional errors of the relative surface locations.

Accurate measures of the relative distance and more importantly the direction between the two wellbores is required. The principal surface method used in deepwater is based on differential global positioning satellite (DGPS) survey methods applied above sea level, not by direct measurement (see Figure 4-8 on following page).

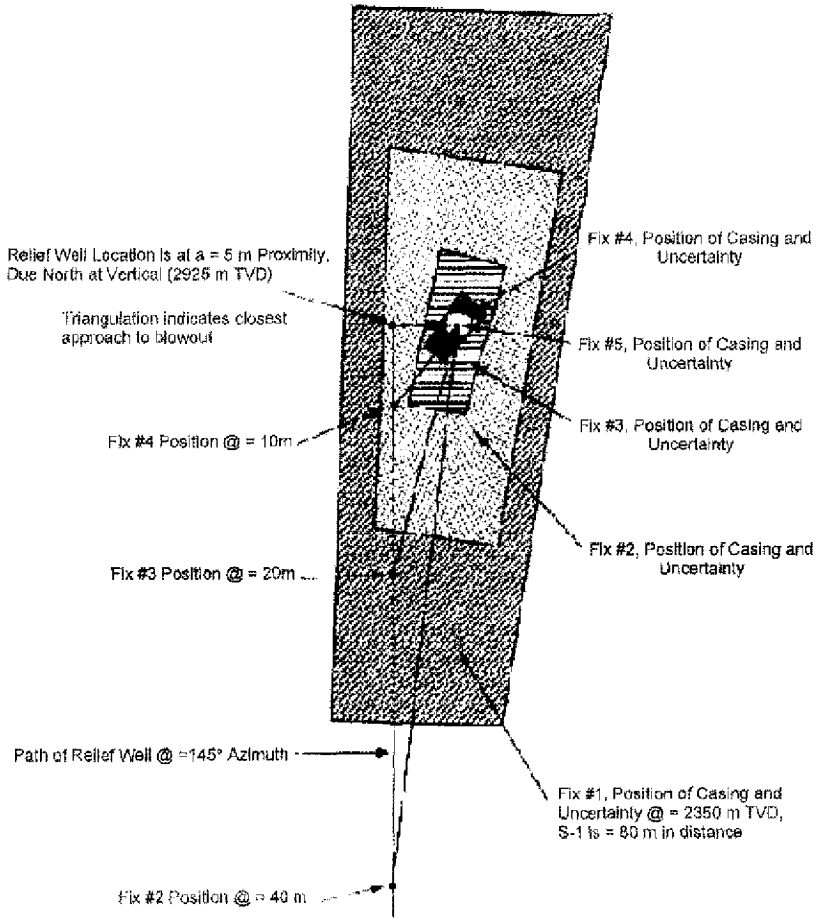

Figure 4-8 Relief well positioning.

4.4.1. GPS and DGPS systems

Most floating drilling rigs have GPS and DGPS systems. These systems depend on timing the arrival of signals broadcast from 24 satellites placed in earth orbit by the United States Department of Defense (DOD). There are plans to increase this number.

A method of triangulation can be used in a computing receiver that contains data on the relative position of each satellite. Handheld GPS devices are now common, and provide a typical GPS accuracy of approximately 10 meters. The DOD places error in the broadcast signal that limits civilian GPS accuracy. The DOD-induced systematic error and other natural error sources limit GPS accuracy.

Differential GPS survey device operations

Differential GPS survey devices use a second or multiple GPS receiver(s) located at a known reference station(s). The signal is obtained real time from this nearby offsite GPS receiver that is used to calibrate the GPS survey receiver. This is typically done through digital radio transmission.

The "differential" between the calibration station's known position and the GPS survey position is then applied to the field GPS survey tool to "correct" for the systematic errors (both induced and natural). The same set of satellites must be used and the relative angle of these satellites above the horizon should be nearly equal.

Deepwater impacts on accuracy

Accuracy is impacted by the distance of the reference station from the field survey station. As drilling moves into deeper water and farther from nearby fixed platforms, the distance from the reference stations and the field stations increases positional uncertainty.

The routine used to survey in the blowing well must be repeated for the relief well. The operator must work closely with the differential survey vendor to minimize error.

DGPS survey report is essential for relief well planning

The operator should file away a detailed DGPS survey report, including the digital raw DGPS survey data in the well file to allow post processing and calibration for relief well planning. There may be no way to check the blowout position if this data is not saved.

Horizontal offset

The horizontal offset from the rotary to the mudline needs to be reported. Dynamic position systems seldom have any offset on rig-up. Anchored systems in higher current areas

in deepwater can have some offset due to anchoring position changes. This offset must be known relative to the DGPS survey position.

Secondary DGPS survey after riser is run

As drilling has rarely started when the vessel was surveyed into position, large offsets may require a secondary DGPS survey as rig position can also shift after riser is run.

A common source of error is the reference system used for North, as indicated below:

Common source of error

- MMS uses "Grid North" versus True North
- MWD survey tools take measurements in magnetic North.

Magnetic pole is subject to drift

The difference between Magnetic North and True North varies as a function of location of the survey to the magnetic pole. This difference is known as "Magnetic Declination". Unfortunately the magnetic pole is subject to drift. At higher latitudes this drift can impact survey accuracy.

When a relief well is drilled, all blowout survey data is inspected and accurate declinations are applied to the raw magnetic survey data. Historical magnetic declinational data can be obtained from the United States Geologic Survey. All surveys are then corrected to "True North" using the best known declination data.

4.4.2. Rate Gyros

It is common in relief wells to use rate gyros. These gyros are built with accelerometers and a second gyro in a system that measures true north from the torque sensed off the spin of the Earth. Sunspots and magnetic hot spots do not impact accuracy. Survey accuracy is at least an order of magnitude better than MWD magnetics.

Running rate gyros at each casing shoe assists in positioning relief well

It is recommended that deepwater operators plan to run rate gyros at each casing shoe starting at 13-3/8" to assist in positioning a relief well. This would greatly assist and speed a relief well intervention program.

A commonly used relief well directional plan comes behind and chases down the blowout.

Thus a cumulative error that combines uncertainty in both the relief well and blowout impacts well intersection. The sources of error are:

- Surface location error
- Surface to mudline offsets
- Downhole survey error
- Survey device error
- Reference: system correction error

Electromagnetic ranging tools are used to overcome the cumulative uncertainty summarized above. If the error is great then an uphole reference or tie-in is needed to get the two wellbores within the detection range of the device used. The need for establishing uphole well proximity is reduced if the blowout well path is known accurately.

Electromagnetic ranging

Electromagnetic ranging is a tool of orientated magnetometers that triangulate the induced or static magnetic field present around steel tubulars located within the blowout wellbore. The induced magnetic field devices use downhole current injection to make a stronger magnetic field around the blowout tubular goods and thus have a better range capability. Targeting information is then given as to distance and direction to the blowout, referenced to a depth in the relief well.

Experts in relief well planning that have a proven track record of successful relief well intercepts and kills should be used.

4.5. Dynamic Kill Considerations

Flow path

As in land or offshore operations, the potential flow paths from the well are manifold. In this section we will not attempt to be exhaustive in our flow path descriptions, but only to cover the more likely flow situations.

Open wellbore with no tubulars downhole

One possible flow path is up an open wellbore with no tubular goods downhole. Variances here would depend on the amount, if any, of open hole versus the amount that is cased.

Downhole tubulars

The second flow path would be if there were tubulars in the well and flow exits the formation through these tubulars. A large number of variables can be encountered such as parted drill pipe, washed out tool joints, or the possibility of corkscrewed pipe which may offer significant restrictions to a flow.

Annulus cross section between wellbore and tubulars

There are combinations which can occur where the flow path is up an annulus cross section between a wellbore and tubulars within the wellbore. Additional complications can be flow up a multiple path for some limited distance and then into a secondary path of different geometries. An example could be flow up a tubular section into an open hole or flow up both an annulus and a tubular section and then into open hole.

Underground flows

Underground flows can occur with the most frequent receiving zone to be the casing shoe of the last string of pipe. If one examines formation fracture gradient versus depth and superimposes a flowing well pressure gradient, the reason for this becomes clear as the greatest pressure differential will normally be at the last casing shoe. This pressure differential can be greater offshore because of the typical fracture gradient in deepwater as is shown in the figure on the following page.

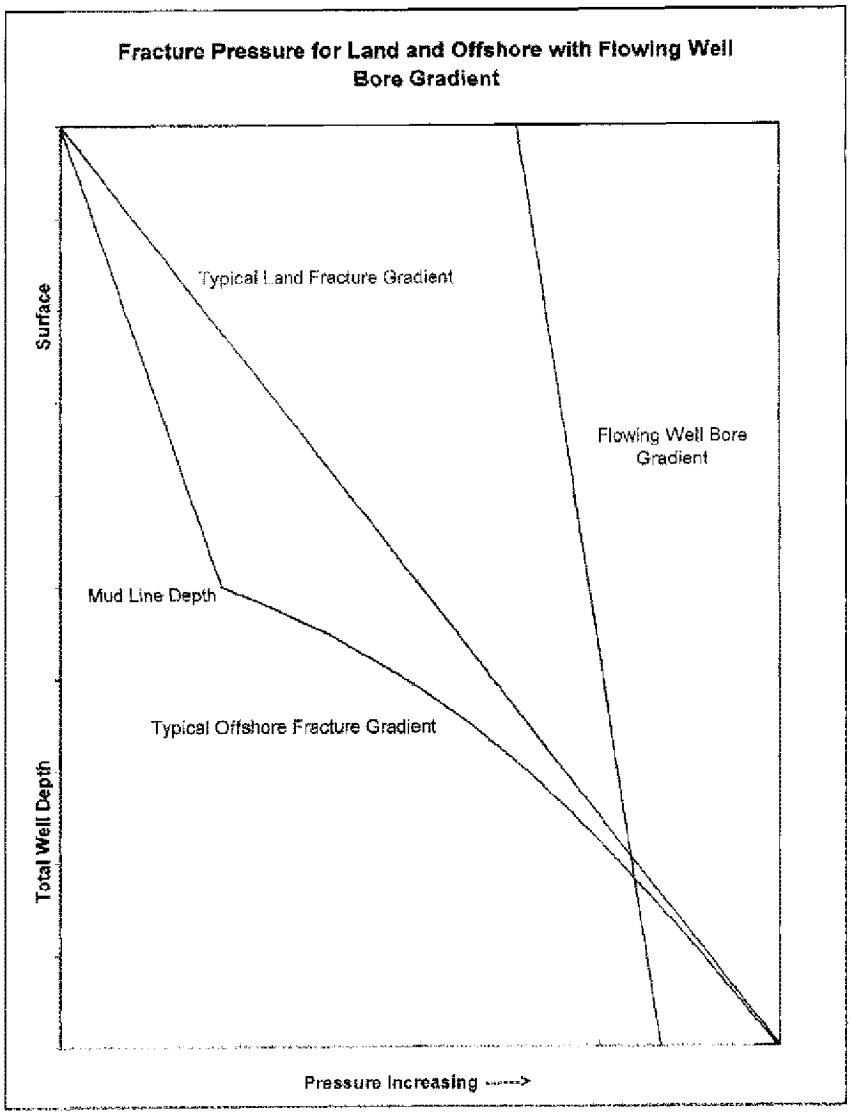

Figure 4-9 Fracture pressure for land and offshore with flowing wellbore gradient.

4.5.1. Restrictions to Flow

Flow from a wellbore will be restricted by one or more of the following mechanisms.

Rapid draw down
- **Low permeability formation**
- **Short exposed formation**

The first restriction to flow can be within the formation itself. This would happen in a zone which has relatively low permeability or a limited length of open formation to a wellbore. In this case, the initial flow from a blowout can be large but will decline rapidly with time as the formation immediately around the wellbore is drawn down.

Minimal draw down
- **High permeability formation**
- **Lengthy exposed formation**

The contrast to this situation is a zone of very high permeability or a large amount of formation open to the wellbore such that there is little or no draw down. In this case flow from the formation is limited by the wellbore and surface mechanics.

Surface mechanical restrictions

Surface mechanical restrictions could be chokes, flow lines, small diameter leaks, or a seawater head in the event of a deepwater uncontrolled flow.

A wellbore will always offer some resistance to flow. In the case of very long wellbores or wellbore flow paths with small cross sectional areas, this resistance can be high and will be the limiting factor in how much the well can produce. However, there have been events in the past where very prolific reservoirs blow out through large casing strings and large open hole diameters. In these cases, even though the wellbore is the restricting element, flow rates of thousands of barrels per day and hundreds of million standard cubic feet per day have been seen.

Seawater head

In a subsea environment, there will always be a seawater head to aid in choking any flow. This seawater head will in effect be a choke of constant backpressure which never wears or cuts out.

Flow velocity

Flow velocity when dealing with formation liquids is straightforward and is inversely proportional to the cross sectional area of the flow path. This means that in a

constant area flow path, the flowing velocity is as high at the bottom of the wellbore as it is at the top.

Compressible fluids have much higher velocity near wellbore top

When dealing with compressible fluids, however, the flowing velocity is much higher near the top of the wellbore than it is near the bottom. The theoretical maximum gas velocity exiting at atmospheric pressure is the speed of sound unless there happens to be some very critical nozzle design at this exit.

Mach 0.3 to Mach 1 acceleration in 5 pipe diameters

The major portion of the frictional pressure drop occurs near the surface in these cases as the gas expands and the velocity increases rapidly. According to gas tables for gases of a 1.4 specific heat ratio, the gases will accelerate from about Mach 0.3 to Mach 1 in a pipe length equal to about 5 pipe diameters, and from Mach 0.5 to Mach 1 in a pipe length equal to about 1 pipe diameter.

Gas entry speeds may be low

However, in a well of significant depth, even with a gas exit velocity of Mach 1, gas entry speeds may be of very low amounts and entry Mach numbers of the order of 0.001 or less. Even at a considerable distance higher in the wellbore, flow velocities may still be low. This allows for a relief well intercept at levels much higher than the TD of the well which still results in a successful pumping attempt.

Seawater backpressure

The effects of seawater backpressure are significant. The chart below shows the maximum seawater depth to achieve sonic flow exits for 0.2 psi per foot pore pressures versus well depth. In designing a well control pumping job, this simply means that the gas flow will not be able to lift and exhaust the pumped in liquids as readily because of the seawater backpressure.

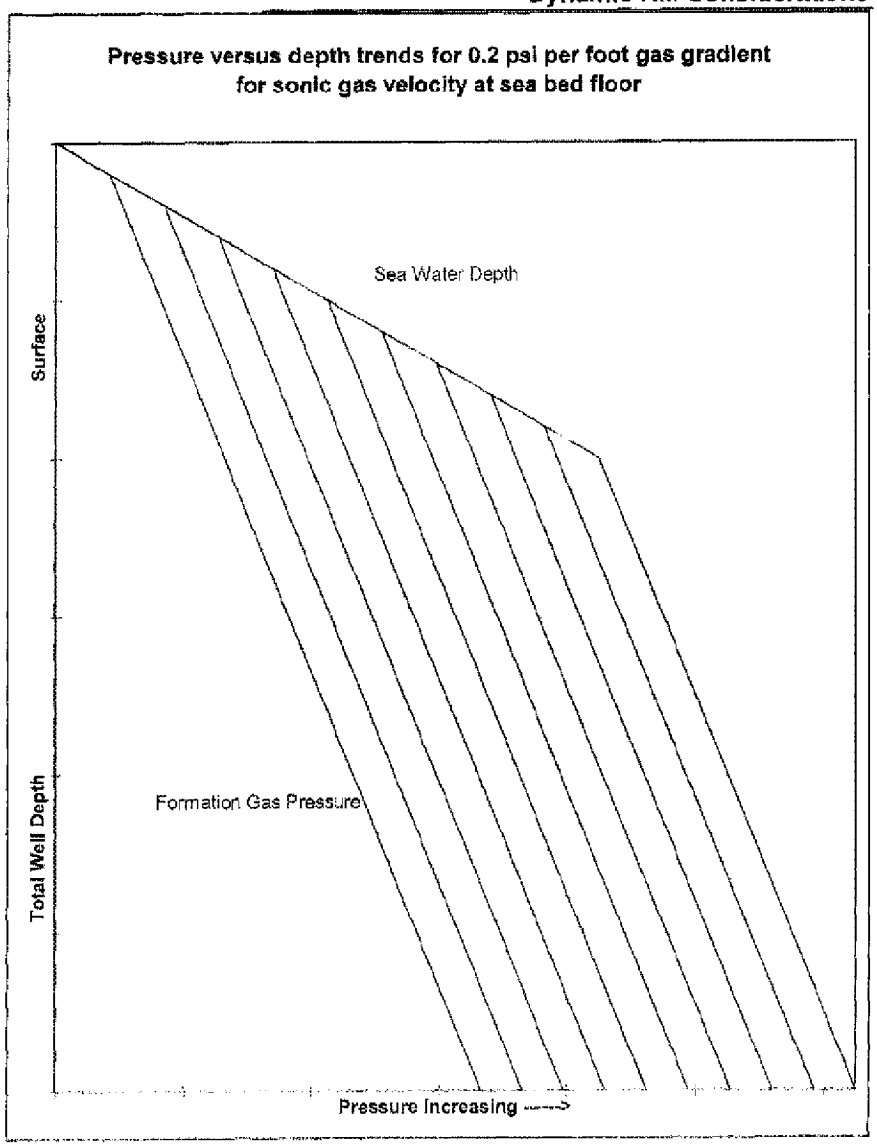

Figure 4-10 Pressure vs depth trends for 0.2 psi per foot gas gradient for sonic gas velocity at sea bed floor.

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4.5.2. Formation Draw Down

Draw down zone

Often during a blowout, the flowing bottom hole pressures are considerably lower than the original reservoir pressure. As the well flow continues in time, this drawdown zone reaches farther out into the reservoir. This depletion will sometimes be obvious because of a reduction in formation flow rate, while at other times, especially in the case of a well flow which is mechanically restricted, this will not be apparent at all.

Depending on the particulars of the well which is flowing, this can be advantageous to consider when designing pumping flow rates, horsepower, and fluids for a relief well kill. The time it takes to complete a relief well may result in a significantly reduced blowout flow and one which is much easier to control. This saves rig-up space offshore, fluid volumes, and mobilization complexity.

4.5.3. Relief Well Intercept Point

One of the variables which is most easily controlled with today's technology is the intercept point of the flowing well by the relief well.

Intermediate depth intercept point

As discussed previously, in some cases, this intercept need not be made at the total depth of the flowing well but rather at some intermediate position. Other factors which may enter into this decision is the nature of the wellbore in the flowing well. If it is a well which is being drilled, then there will likely be only open hole with perhaps some tubulars in this open hole such as the bottom hole assembly from a drillstring. However, in the event of a blowout starting with no tubulars in the well, the flowing well consists only of open hole.

Blowouts in producing wells

A substantial percentage of blowouts occur in producing wells and these may have a variety of completion assemblies in them. Careful consideration must be given as to where these are intersected as some of the completion concepts such as gravel packs are specifically designed not

to allow formation fines to enter the wellbore, and will restrict or completely eliminate the introduction of particle weighted material from a relief well into a flowing production wellbore.

The offsetting advantage of a producing well is that there will be a large magnetic mass with which to range on for a casing-to-casing intercept at the desired point. Also, there will be a reduced number of unknowns when drilling a relief well into a production well as there will not be the amount of open hole which could either cause loss of returns prematurely or the encountering of a charged zone which can create well control problems within the relief well itself.

Production wells: location of packers, perforations, ends of tubing, other wellbore restrictions

In production wells, the location of packers, perforations, ends of production tubing, or other wellbore restrictions which could play an important hydraulic role should be considered. When injecting kill fluids in a relief well, it is desireable to have the most vertical height and to have the most favorable frictional flow geometry. Thus, if there is any restriction which can cause increased frictional pressure drops within the flowing wellbore, these should be used if possible as they will only help to make a kill easier.

4.5.4. Formation Leakoff

Relief well hydraulic conduit

When pumping from a relief well into a flowing wellbore, there will be restrictions on the maximum allowable pump rate. This maximum rate will be determined in part by the hydraulic conduit of the relief well. Examples here would be whether the drill pipe in the relief well would be used for pumping purposes or whether the annulus would be used.

Pumping through drill pipe and/or annulus

In some cases it may be a requirement that both paths be employed for relief well pumping, but bottom hole pressure measurement and subsequent analysis of the effects of the pumping operation may be hampered if both strings are used. Additional considerations would be the type of fluid within the relief wellbore at the time the intercept is made

because if returns are lost, the fluid within the relief well could be the first fluid into the flowing well.

Potential for lost returns

A second limitation on pressure will be the fracture gradient of the formation at the point of intercept. If this is exceeded, then formation leakoff could become excessive with a reduced amount of liquid pumped in actually going into the flowing well. In all pumping operations where a formation is exposed, there will be some leakoff. This leakoff must be contained to manageable amounts for a relief well kill to be successful.

Cement for permanent plugging

The ultimate end of a relief well pumping job will be to place a fluid with sufficient density into the flowing well to stop all flow within the well and contain formation pore pressure. This may include cement for permanent plugging. If there is some separation between wellbores, then this may become more complicated in that sufficient permeability must be present or generated within the formation to allow fluid with solid particles to be pumped across.

Light fluid followed by weighted mud or cement

In some cases, it will be an advantage to pump a light liquid such as water to generate increased flow path capabilities and to then follow the water with a drilling mud or cement. The water pump rate does not have to be of an amount to actually kill the flowing well as long as the path is generated for a later introduction of a liquid which will kill the flowing well. This would require smaller pumping plants on the surface as the rates and consequent pressure would be lower with the end result being less horsepower required.

4.6. Spill Control

Oil exploration and production in deepwaters present many challenges, one of which is preparedness to respond to a spill from a deepwater blowout should the preventive measures fail to control the produced well fluids.

Historically, exploration & production (E&P) around the world has experienced very few major spills and none from a deepwater well blowout. Available worldwide statistics point to only a 0.214% chance of a deepwater blowout (DEA 63 Study).

Few incidents of significant spills

The United States is a good example. From 1962 through 1997, there have been only three E&P spills of over 1,000,000 gallons (23,800 bbl.) out of a total of 49 spills nationwide: 1) an offshore pipeline spill of 160,700 bbl off the coast of Louisiana on 10/1/67; 2) 28,800 bbl spilled on 3/10/70 from a production well off of Venice, Louisiana; and, 3) a 53,100 bbl spill from a production platform also off the coast of Louisiana (Oil Spill Intelligence Report, March 1998). Preventative measures have paid off worldwide as well as in the Gulf with the last major spill occurring there over 27 years ago.

When oil from a subsurface oil spill reaches the surface, its movement is governed by a combination of wind and surface currents. This is the same whether the oil comes from a shallow well or a deepwater well. Historic data is lacking in deepwater well blowouts, and, in fact, there have been only a handful of shallow water well blowouts, the most notable being the IXTOC blowout in the Bay of Campeche in about 50 m of water in 1979. This type of blowout allows the oil to quickly reach the surface with little time to interact with the water column. The IXTOC well blowout had emulsified oil reaching the surface that quickly de-emulsified to black oil a few miles from the stricken platform.

4.6.1. Plume Dispersion

The DEA 63 study combines the results of theoretical work and with data on actual field experiences and observations in an attempt to get a clearer picture on what might happen as oil from a deepwater well blowout rises to the surface. Key points from the study are discussed below.

Any subsurface release of a gas and/or oil release undergoes both physical, chemical, and biological reactions that affect the oil as it rises as well as when it is on the surface of the seawater.

Shallow water release compared to deepwater release

A shallow water release of oil and gas is generally released under high pressure and high velocity, resulting in the gas, oil, and water mixing, and the mixture being carried quickly to the surface as the gas expands under ever decreasing hydrostatic pressure. This is contrasted by a deepwater release where the oil and gas is under high hydrostatic pressure and low ambient temperature. There is speculation that the oil and gas could combine with the water to form almost neutrally buoyant hydrates, thereby negating the effect of an expanding, rising gas as experienced in a shallow water release.

Formation of neutrally buoyant hydrates

If the driving buoyancy of the expanding gas is eliminated and the oil droplets become neutrally buoyant, the following questions arise:

- Does the oil rise to the surface under gravity forces alone?
- Is the oil captured in the many subsurface cross currents and transported miles from the blowout before surfacing?
- Does the oil reach neutral buoyancy in one of the stratified layers in the oceans and never surface?

All plume models currently in use assume that the plume will rise through a uniform water column. In reality, the waters where deepwater exploration is taking place are often heavily stratified with varying salinity, temperature, and current layers.

Some research suggests that cross currents will have minimum effects on the behavior of a rising plume while other research suggests that stratified layers of warm and cold sea water of varying salinity concentrations could result in shearing of the rising plume, separating small droplets of oil from the plume that rise at a slower rate than the main body of the plume.

The amount of oil and gas that dissolves into the water column depends on the rate of emulsion formation or lack of emulsion formation, the bubble surface area, and physical/chemical composition of both the bubble and its surrounding environment. It is uncertain whether the gas and oil would separate as they rise to the surface and the gas surface miles from where the oil surfaces (assuming it does). The most recent efforts to address some of these issues comes from the US Department of the Interior's Minerals Management Service (MMS).

4.6.1.1. Chemical and physical changes: subsurface

Oil emulsions

Components linked to emulsion formation
- **<2% asphaltines = low probability of emulsion**
- **2-5% = ?**
- **>5% = high probability of emulsion**

As in the IXTOC spill in 1979, deepwater releases may interact with the surrounding water to form oil/water emulsions. The data bank on shallow well blowouts suggest that three components are linked to emulsion formation: asphaltenes, resins, and waxes, with asphaltenes having the most influence on emulsion formation. Data suggests that oils with less that 2% asphaltenes tend not to emulsify, between 2% and 5% is a grey area, and greater than 5% would tend towards a stable emulsion formation.

Solution

In addition to the potential for emulsion formation, other chemical changes that help abate the long term impact of a deepwater well blowout take place as the plume rises to the surface.

The first of these processes is the dissolving of low molecular weight hydrocarbons from the oil into the

seawater. In addition, some of the non-oil components also dissolve into the seawater. These include the light alkanes (propane through isopentane), and light aromatics (including benzene, toluene, and xylene). The degree of impact of various crude oils is largely a result of the percentage of these light aromatics contained in the oil.

The dissolving of these compounds begins as soon as the oil comes into contact with seawater and may play a large part in the various chemical processes taking place, since the height of the plume is greater in deepwater, increasing the amount of time the oil is exposed to the seawater before it reaches the surface.

Subsurface Dispersion

Natural subsurface dispersion in a deepwater well blowout is also expected to be more significant due to the reaction of the rising plume with the shearing effects of multi-layered sub-surface currents. The naturally dispersed oil may remain trapped below the surface in these various stratified layers of water. If so, it may biodegrade or combine with sedimentation in the seawater and slowly settle where biodegradation will also take place.

Sedimentation

During sedimentation, the hydrocarbon molecule attaches itself to a sediment particle in the seawater and the subsequent union is of such density that causes it to sink. In the vicinity of the deepwater blowout, the sediment/oil mixture will settle into a cooler, less biologically active environment than would be found in a shallow water depth.

The oil/sediment mixture could persist there for years as anaerobic decomposition slowly occurs. This could help explain why occasionally tar mats are washed ashore by storms years after a spill occurs.

4.6.1.2. Chemical and physical changes: surface

Once the hydrocarbon reaches the surface, physical and chemical changes continue to occur.

Spreading

Once on the surface, the oil spreads. Initial spreading is controlled by the density difference between the oil and the seawater; which is influenced by wind, waves, and surface currents. As time passes, viscosity and surface tension control the spreading of the surface slick. Spreading results in increased spill surface area,, which increases exposure to the biochemical (biodegradation) and physical processes (evaporation) that further reduce the size of the slick.

However, spreading has the following disadvantages:

- It decreases the effectiveness of mechanical cleanup
- It increases the potential of the spill eventually impacting land
- It increases the potential that aquatic species, birds, and sea-going mammals might be impacted

Evaporation

Evaporation occurs when low to medium weight hydrocarbons in the surface slick volatize into the atmosphere. Spreading enhances this process. The warmer the climate, the larger the evaporation component will be.

This phenomena, known as the "weathering of crude oil," starts almost immediately as the oil reaches the surface. The lighter the crude oil, the higher the percentage of evaporation.

As the light fractions of the oil are lost, the remaining oil becomes more viscous. Evaporation is most active in the first few days of the spill and, as it progresses over several days, emulsification and tar ball formation may commence. This causes a corresponding increase in the specific gravity that will result in the sinking of the remaining oil.

High volume loss in first 12 hours

Some research shows that upwards of 30% to 60% of most crudes are lost to evaporation during a spill. Up to 50% of this loss has been known to occur in the first 12 hours (Brown and Huffman, 1976) and result in a substantial reduction of the oil remaining on the surface. The tar balls that are created may remain in the marine environment for long periods of time. Frequently, they end up being washed up on shorelines many miles from the spill.

Photochemical Oxidation

Oil can interact with sunlight and photo-oxidize into more soluble compounds than the original oil. This process also aids in the reduction of the amount of oil on the surface. Thin slicks/ sheens can decompose in just a few days.

Microbial Degradation

Bacterial and fungal microorganisms capable of digesting and decomposing oil are present in all oceans. This biodegradation converts the hydrocarbons in the crude oil into soluble oxidized byproducts which eventually convert to carbon dioxide and water.

The speed of this process is controlled by factors including:

- bacteria concentration at the spill outset
- the dissolution of light ends from the oil into the seawater
- the availability of phosphorous and nitrogen as nutrients
- the seawater temperature
- the concentration of dissolved oxygen in the water
- the amount of oil spilled

Typical concentrations of bacteria and fungi in seawater are in the 10 per liter range, but can range higher in areas where there are natural oil seeps or frequent oil spills.

4.6.2. Surveillance and Monitoring

Daylight monitoring by fixed wing aircraft or helicopter

Once the oil reaches the surface of the seawater, it can be tracked by a number of methods. During daylight hours the primary method used to maintain surveillance and monitor

the movement of a surface oil slick is either a fixed wing aircraft or a helicopter. The fact that the deepwater release is typically remote from land may affect the logistical support of said surveillance.

Large fuel capacity for aircraft and helicopters

In deepwater surveillance, time on station vs. time to refuel becomes an issue for helicopters and fixed wing aircraft. Fixed wing aircraft and helicopters with large fuel capacity will be required to maintain station at the spill site to guide both dispersant applications as well as mechanical recovery vessels.

During day and night operations, several governments have utilized some form of electronic surveillance and monitoring instrumentation (side scanning radar, infrared [IR] cameras) to monitor as well as detect spills. Some nations utilize these devices to monitor discharge activities of offshore platforms, vessels, barges and fixed shoreside facilities.

Infrared cameras

In oil spill response, the IR camera can be used to monitor the movement of surface slicks when visual observation cannot be used, and to allow night time mechanical operations to occur. Surface infrared units in conjunction with the USCG air eye infrared system was used successfully in the Buffalo 292 barge breakup in Galveston to conduct successful night operation oil recovery from surface vessels using conventional mechanical skimmers.

Both computer and manual spill trajectory models have been used to enhance electronic surveillance and monitoring of surface slicks. Spill trajectory models can give air monitoring/surveillance efforts a better idea of where to initiate searching for the slick with their electronic systems after night has fallen and where to continue additional flights during the night. This is important when trajectory models predict a current and/or direction change of the slick during the night.

4.6.3. Response Strategies

Mechanical Containment

Mechanical containment and recovery: Low recovery expected

Booms. Historically, the chemical and physical processes described above account for a far greater percent removal of the oil, sometimes in the 50 to 70 percent range, than mechanical means. However, improvements in recovery success have been demonstrated recently in the Gulf of Mexico, where dedicated oil spill response vessels recovered 33% of the oil spilled from a barge breakup in Galveston Bay, Texas.

In open sea conditions, it is doubtful that mechanical containment and recovery techniques alone will be effective in containing and skimming oil from a deepwater well blowout.

Static booms useful up to up to approximately 1 knot of current

Floating booms, the primary means of containing floating oil in the open sea, act as barriers to prevent the oil from spreading. Most booms consist of a flotation section (either solid or air filled) above the surface of the water, and a skirt section below the water surface. Ocean booms are specifically designed in size and strength to counteract the high sea and wind conditions of an open ocean environment. Most open ocean booms are designed to function in currents of less than one knot, or the oil may entrain (flow under) the skirt of the boom. Currents of greater than one knot require boom operators to either boom the oil going with the current, or boom backing down from the direction of the current so as to avoid the oil entrainment problem.

Subsea collectors/containment. The 1969 Union Oil blowout in the Santa Barbara Channel in California, the 1977 blowout in the North Sea, and the 1979 Ixtoc I blowout in the Bay of Campeche created impetus to develop better concepts and perform tests on subsea blowout containment devices. The Ixtoc I "Sombrero" containment collar recovered 1.5 million barrels per day, but water entrainment due to mixing with the gas resulted in only a 2% oil content. Additional efforts on developing

subsea containment and collection devices have lapsed in recent years due to the absence of severe subsea blowouts.

Most subsea collection/containment devices have been designed either as bell-shaped devices, rigid-wall cylinders, or flexible columns that do not require any external energy source. All of these types of designs tend to limit access to the wellhead and prevent the use of other types of well control measures (DEA 63 study).

4.6.4. Recovery

Storage may be the limiting factor in any deepwater well blowout where mechanical containment and recovery devices are used.

Storage onsite may be a limiting factor for deepwater spill control

Skimmers

Open ocean surface skimmers can be categorized into two general main groups: 1) weir skimmers which are very high volume, and 2) oleophilic (oil loving/water hating) belt/rope skimmers.

Weir skimmers

The inherent drawback to the weir skimmers is that unless the skimmer is operating in a large pool of oil, the weir will recover a large volume of water along with the oil. The volume of water recovered could be as high as 90% to 95% of the total volume. This restricts the amount of time the weir skimmer can operate unless there is sufficient storage capacity onsite for the recovered product.

Oleophilic skimmers

Oleophilic skimmers, on the other hand, have the advantage of skimming 80% to 95% oil in most sea conditions. The better the sea conditions, the higher the percentage of oil recovered. This is true of weir skimmers as well.

Oleophilic skimmers operate at a much lower skimming rate than their weir counterparts so that if sufficient storage is available, the volume of oil recovered by the two types of skimmers may very well be roughly equal.

All surface skimmers are part of an overall system that includes the following components:

- an ocean/open seas vessel as the operating platform for the skimmer
- a containment boom to concentrate the oil
- a second ocean type vessel to help with oil containment
- an ocean-going storage barge to store and process the recovered product

Typical offshore recovery system configurations include the J-shaped, the U-shaped, and the double J-shaped.

J-shaped recovery configuration

The J-shaped recovery configuration includes the operating platform vessel, the skimmer, sufficient ocean boom attached on one end to the skimming vessel to create a J-shaped containment area on one side of the skimming vessel, the second ocean vessel to help maintain the J-shaped containment area, and a storage barge to store the recovered product.

Double J-shaped recovery system

The double J-shaped configuration simply duplicates a second containment/recovery concept so that there are two Js containing and skimming simultaneously, one on the port side and one on the starboard side of the operating platform vessel.

U-shaped recovery system

In the U-shaped recovery system, the containment boom is guided by two ocean going vessels, and the operating platform (skimmer) vessel operates independently of the booming configuration, either from inside the U-shaped containment area or from outside of it with the skimmer being placed inside.

Newer customized dedicated skimmer vessels are complete with onboard storage, onboard oily water separators to concentrate the oil, and oil heaters to thin the recovered oil.

Storage

For many years, regulatory agencies around the world have emphasized the need to have sufficient amounts of boom and skimmers to contain and cleanup the oil.

Worst case deepwater spill, insufficient storage

Given a worse case deepwater well blowout of 30,000 - 40,000 bbls/day, in certain areas of deepwater E&P, the inventory of dedicated spill response oil storage may be insufficient to support mechanical spill response efforts in the early hours of a response when the surface slick is most concentrated and more easily skimmable.

4.6.5. Disposal

Disposal options depend on the condition of the recovered oil.

If the product is relatively fresh, free of emulsification, and has been processed through an onsite oil-water separator or gravity dewatered on an onsite storage tanker/barge, then it is likely that this oil can be taken to a shoreside facility and directly blended into other crude oil stocks and processed through a refinery.

If the recovered oil has not been dewatered onsite in the spill area but is still relatively fresh and not emulsified, it may be taken to a shoreside facility for processing.

The major problem then becomes the discharge/disposal of the water fraction of the mixture by the shoreside facility processing the oil, which is beyond the scope of this document.

Dispersants

Chemical dispersants are surfactants (surface active agents) that are used to break down the crude oil into tiny droplets so that they disperse into the water column where

indigenous bacteria can biodegrade the droplets into harmless by-products.

Dispersants are now more widely used in the United States for open ocean spills. Several areas including the Gulf of Mexico now have dispersant pre-approval plans in place. Application of dispersants can be accomplished by vessels, helicopters with slung spray buckets and fixed wing aircraft (DC-3, DC-4, C-130).

Dispersant dosage

The largest, quickest coverage is provided by fixed wing aircraft with a usual dosage of one part dispersant to 20 parts of oil. A fixed wing aircraft spraying 5 gallons of dispersant per surface acre of oil will achieve this 20:1 ratio. Emulsified oil will require a larger dosage, sometimes 10:1 or 5:1.

While most research indicates that the "open window" to spray dispersants on a crude oil slick is limited to 12 to 24 hours (depending on the type of crude), recent spraying of nine day old weathered and emulsified oil off the coast of Africa implies the "window" may be longer than first thought.

Burning

In-situ burning normally converts hydrocarbon portion of crude oil into CO_2 and water

Surface burning (in-situ burning) is another tool that can be used to help mitigate the impact of a surface oil spill. Approximately 58% of the oil spilled by the Ixtox I well blowout was burned off at the surface. In-situ burning of crude oil normally converts the hydrocarbon portion of the crude oil into a carbon dioxide and water. There is some concern that the non-hydrocarbon portion of the crude will release chemical compounds as a by-product of the burn process.

Recent air monitoring studies indicate that there is more complete combustion with less chemical compounds released to the atmosphere than originally thought. In-situ burning requires relatively "fresh" oil that still contains most of the lighter hydrocarbons and a minimum thickness

(10mm or greater) to maintain combustion. Like dispersants, the window of opportunity for in-situ burning will be limited to the early hours of the spill (unless the spill is ongoing as in a deepwater well blowout).

Boom towed in U-shape configuration between two vessels

To maintain the minimum thickness required, a boom is towed in a "u-shaped" configuration between two vessels through the slick. A portion of the boom must be fireboom, usually 500 ft, so that the boom won't burn up when the oil is ignited. The 500 ft of fire boom is usually accompanied by 400 ft of regular boom, 200 ft on each side of the fire boom used as a "guide boom" along with the fire boom.

Ignition source launched from vessel or helicopter

The ignition source can be some form of burning fuel, flare, or gel launched from one of the two guide boats or flaming napalm gel dropped from an undersiung helicopter "helitorch" specially designed for open ocean burning. While in-situ burning is not feasible in all circumstances, it is one more tool in the response arsenal that can be used to minimize any impacts from a deepwater subsea blowout.

Bioremediation

Use of indigenous bacterial and fungal populations

Microbial degradation of oil slicks from indigenous bacterial and fungal populations in seawater will take place. In recent years there have been several attempts to artificially enhance the speed of the degradation process either through the introduction of additional populations of microbes and/or additional nutrients.

Passive bioremediation relies on using the indigenous population of bacteria in the sea water while enhancing it through one or more of the following additions:

- dispersants (increases the surface area by creating small oil droplets)
- enzymes (to break the oil molecules into smaller fragments) oxygen (if it is deficient in the sea water)
- addition of nutrients (to increase bacterial growth)

Colonies of artificial bacteria specific to hydrocarbons

Active bioremediation involves the addition of non-indigenous colonies of bacteria to those already present in

the seawater. These colonies of artificial bacteria are specific to hydrocarbons, the heavy metals and aromatic compounds in the oil, and may include enzymes that will help to further break down the molecules in the oil, as well as necessary vitamins, minerals and amino acids to boost bacterial growth.

Aircraft applications of this mixture is the preferred method, but vessel application can be used as well. Bioremediation offers promise as another tool to help combat a deepwater subsea well blowout.

4.6.6. Conclusions

Spill control strategy combines the following:

- **Mechanical containment and recovery**
- **Dispersant application**
- **In-situ burning**

A combination of the following operations offer the best strategy to minimize the effects of a deepwater well blowout:

- mechanical containment and recovery
- dispersant application
- in-situ burning

Additional research needs to be conducted that will determine what really happens to oil released from a deepwater blowout. The concept of injection at the source of the blowout on the seabed merits further study.

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CHAPTER 4. EMERGENCY RESPONSE INDEX

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5.0 TRAINING

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Chapter 5. Training

Well Control Training Subcommittee
Richard DeBuys (Chairman), WCS – Well Control School
Kerry Girlinghouse – Chevron USA
Richard Grayson – R&B Falcon Drilling, Inc.
Allen Kelly – Diamond Offshore Drilling, Inc.
Rogers Louviere – Texaco Exploration and Production, Inc.
J.D. (Dado) Matkins – Transocean Offshore, Inc.
Glen Merrifield – Diamond Offshore Drilling, Inc.
Otto Luiz Santos – Petrobras
Mickey Welch – Diamond Offshore Drilling, Inc.

C&K	Choke and kill lines
DP	Dynamically positioned
DPP	Drill pipe pressure
ECD	Equivalent circulating density
FIT	Formation integrity test
LCM	Lost circulation material
LOT	Leak-off test
LWD	Logging while drilling
MWD	Measurement while drilling
OBM	Oil-base mud
PWD	Pressure while drilling
ROV	Remotely operated vehicle
SBM	Synthetic-base mud
SWF	Shallow water flow

CHAPTER 5. TRAINING
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5.1 Deepwater Well Control Training: Overview

5.1.1 Summary

The following guidelines are designed with the intent to enhance current well control training programs to include more timely information relative to deepwater drilling and well control. This discussion is broken into curriculum considerations, well control simulator deepwater upgrades, and practical well control training for deepwater operations.

5.1.2 Well Control Curriculum Considerations

The curriculum considerations that are presented for inclusion in well control training programs are based on the findings of the IADC Deepwater Well Control Task Force findings described in earlier chapters. Section 5.2 addresses the specifics of the proposed curriculum guidelines addressing deepwater operations.

5.1.3 Well Control Simulator Requirements

Well control simulators currently address training needs for land and shallow to medium water depths

Well control simulators are currently addressing the needs of land and shallow to medium water depths for the most part, but additional upgrades are needed to meet deepwater well control training needs. These upgrades include not only some mechanical upgrades to the simulators, but also software needs (e.g., compressible fluids). It is recognized that emerging technologies (e.g., interactive CD) are being developed and may do an excellent job in the near future, but the comments pertaining to equipment upgrades specifically address the current portable and full scale simulators. Section 5.3 develops needs assessment specific to simulators and simulations.

5.1.4 Practical Well Control Training Guidelines

Several well control procedures necessitate alteration and adaptation for deepwater operations and resulting training

simulations. Section 5.4 lists those procedures directly affected by water depths. These procedures have been taught for years in well control schools, but should be reviewed to ensure they properly address deepwater operations. Again, the detail of some of these procedures are specific to company policy, but the generic procedural upgrades for deepwater should be taught to personnel being trained for deepwater well control.

5.2 Deepwater Well Control Curriculum Considerations

5.2.1 Summary

The following section describes those topics that relate specifically to deepwater well control. These items should be taught in addition to typical well control topics. In fact, the topics are relatively the same but materials identified by the IADC Deepwater Well Control Task Force should be included. Topics that relate to well control, other than drilling, are included as reference materials as contained in Chapters 1 through 4 of this document.

5.2.2 Well Control Curriculum Considerations

The topics listed below relate specifically to deepwater drilling operations and can be located elsewhere in the *Deepwater Well Control Guidelines* by using the cross-references provided.

Suggested Topics for Well Control Curriculum

Shallow Water Flow	1.2	Shallow Water Flow Control Guidelines
	2.8	Well Control Prior to BOP Installation/SWF
Drilling Fluids	1.3	Drilling Fluids Considerations
	1.3.2.1	Thin Margins
	1.3.2.2	Losses, Fracture Propagation
	1.3.2.3	Ballooning
Drilling Fluids, cont.	1.3.2.4	Equivalent Circulation Densities
	1.3.2.5	Gas Solubility (OBM, SBM)
	1.3.2.6	LOT (OBM, SBM)
	1.3.2.7	Fluid Compressibility (OBM, SBM)

	1.3.3	Fluid Storage
	1.3.3.6	Weighted Systems for SWF Kill
	1.3.3.7	Barite Storage/Mixing Capacities and Rates
	1.3.3.8	Kill Weight Mud
	1.3.3.9	LCM Effectiveness (OBM, SBM)
	1.3.3.10	Gunk Squeezes/Barite Plugs
	1.3.5.5	Temperature Stability
	1.3.5.6	Mud Properties
	1.3.6.4	LCM Formulations
	2.10.5	Riser Margin
Hydrates	1.4	Hydrates
	1.4.2	Requirements for Hydrate Formation
	1.4.3	Pre-Planning and Prevention
	1.4.5	Inhibition
	1.4.6	Potential Problems
	1.4.7	Defense
	1.4.8	Heat Generation Systems
	1.4.9	Remediation Guidelines
	2.7	Hydrate Prevention/Removal
Kick Prevention and Detection	1.3.5.3	Flow Checks
	1.3.5.7	Kick Detection (Drilling Fluids)
	2.1	Kick Detection
	2.1.2	Mud Density
	2.1.3	Mud Viscosity
	2.1.4	Drilled Cuttings
	2.1.5	Abnormal Pressure Detection
	2.1.6	Environmental Effects
Shut-In	2.2	Shut-in
	2.2.1	Pre-kick Preparation
	2.2.2	Hard Shut-In vs Soft Shut-in
	2.2.3	Annular Shut-in vs Ram Shut-in
	2.2.4	Shut-in while Drilling
	2.2.5	Shut-in while Tripping
	2.2.6	Shut-in while Making a Connection
	2.2.7	Shut-in with Bit above BOPs
	2.2.8	Shut-in while Running Casing/Liner
	2.2.9	Masking of Casing Pressure by High Gel Strength in C&K Lines
	2.2.10	Hang-off Guidelines
		Use of Drillstring Floats
		Use of Drillstring Safety Valves
		Reading Shut-in Drill Pipe Pressure
Circulating to Kill Wellbore	2.3	Circulating to Kill
	2.3.2	Driller's Method
	2.3.3	Wait and Weight (Engineer's Method)
	2.3.4	Bullheading

	2.3.5	Number of C&K Lines
	2.3.6	BOP Separator Effect
Volumetric Method of Well Control	5.3.3	Software Enhancements
Dynamic Volumetric Well Control Technique	5.3.4	Procedural Enhancements
Preventing Lost Returns and Underground Blowouts	2.4	Preventing Lost Returns and Underground Blowouts
	2.4.2	Detection of an Underground Blowout
	2.4.3	Underground Blowout while Drilling
	2.4.4	Underground Blowout while Working Well Over
	2.4.5	Actions in the Event of an Underground Blowout
BOP Cleanout	2.5	BOP Cleanout (Trapped Gas)
Gas in Riser/Riser Diverter	2.6	Gas in Riser
	2.6.2	When to Apply Gas in Riser Procedures
	2.6.3	Considerations for Handling Gas in Riser
	2.6.3.1	Alternatives for Handling Riser Gas
	2.6.3.2	Riser Fill-up Valve Operation
	2.6.4	Timing of Riser Circulation
	3.5	Riser Gas Considerations
	3.5.2	Danger of Free Gas in Riser
Emergency Disconnect	2.11	DP Emergency Disconnect Considerations
BOP Arrangements for Deepwater Operations	3.1	BOP Arrangements for Deepwater Operations
	3.1.2	Number of Rams in a Deepwater Stack
	3.1.3	Placement of Rams/Outlets
	3.2	Choke Manifold
	3.2.2	Overboard Lines
	3.2.3	Mini-Trip Tanks
	3.2.4	Low Pressure Gauges
	3.2.5	Set-up for Riser Gas
Riser System	3.3	Deepwater Riser Considerations
Diverter System	3.4	Deepwater Diverting Considerations
Diverter System Design	3.5.3	Diverter System Design
Control Systems	3.6	Deepwater Control System Considerations
ROV Interventions	3.9	ROV Interventions
	3.9.3	Common BOP Override Functions

5.2.3 Conclusions

The above is not intended to be an exhaustive curriculum outline, but only to emphasize topics pertinent to deepwater well control. It is intended that this listing along with practical training considerations listed below will together provide a well control training road map for deepwater personnel using state-of-the-art knowledge.

5.3 Deepwater Well Control Simulator Requirements

5.3.1 Summary

More flexibility and capability are needed if deepwater and ultra deepwater simulations are to meet the challenge of providing realistic well control training scenarios

The state of the art drilling well control simulators, hardware based and software driven, meet current regulatory body requirements, and as such, no major modifications are required to meet "standard" well control certifications presently in place. However, it is recognized that more flexibility and capability are needed for these simulators if deepwater and ultra deepwater simulations are to meet the challenge of providing realistic well control training scenarios for drilling personnel.

This section will address deepwater simulator considerations in terms of simulator equipment, software, and procedural enhancements as identified necessary for deepwater well control training. It is recognized that some simulators being manufactured may already have some of the enhancements being discussed. No attempt has been made to identify capabilities of various marketed well control simulators, but the intent of this document is to identify equipment and procedural requirements necessary for properly training drilling personnel for deepwater well control. A list of equipment enhancements is provided below.

5.3.2 Equipment Enhancements

The following equipment enhancements are recommended:

1. Pressure gauge at the BOP stack
2. Booster line for the riser system
3. Kill or monitor line gauge in addition to the choke and drill pipe gauges
4. Ability to use second fluid pump to circulate booster line during circulation/riser sweeping
5. Diverter system with valving and flow lines for diverting riser flow to:

- either a trip tank or shale shaker;
- a riser mud/gas separator; and
- either of two opposite overboard flow lines

6. Ability to use top drive equipment
7. Ability to isolate both the choke and kill lines from the riser system and the wellbore (for cross circulating through the choke and kill lines)
8. Ability to hang-off on a ram
9. Fill-up valve in riser
10. Ability to use cement pump for circulating
11. Ability to circulate the choke and kill lines in parallel flow (including proper modeling of the BOP separator effect)

5.3.3 Software Enhancements

The following software enhancements are recommended:

1. Ability to handle either water base or synthetic/oil base fluids, inclusive of fluid compressibility which may allow flow to continue for a short period of time after shutting off the pump(s)
2. Ability to realistically emulate gas in the long choke lines as is found in deepwater operations
3. Ability to simulate viscosity changes and gel strengths for deepwater where temperatures are cold and choke and kill lines are long *(Note: This requires temperature modeling capability as well as viscosity modeling.)*
4. Ability to emulate ballooning formation type scenarios due to high ECDs, allowing trends to be monitored for kick detection in lieu relying on well flow or pit gain
5. Ability to predict size and pressure of trapped gas under closed BOP
6. Ability to simulate gas hydrate complications by blocking a function in BOP stack, thereby inducing a well control complication
7. Ability to program solution gas undergoing phase change (coming out of solution in either OBM or SBM) in riser or choke/kill line(s)

8. Incorporate kicks indicated by MWD/LWD and PWD tools on driller's data display monitor display *(Note: Alarm settings, as well as software setup options, would need to be incorporated in the system if this function is to be utilized.)*
9. Ability to emulate stripping operations
10. Ability to handle two phase flow in the choke line when implementing a dynamic volumetric method of well control (i.e., cross circulating the choke and kill lines while allowing gas to migrate up the wellbore and using shut-in drillpipe pressure for BHP control)
11. Support stack cleaning, inclusive of u-tubing gas from within the stack
12. LOT or FIT option

5.3.4 Procedural Enhancements

The following procedural enhancements are recommended:

1. Perform well control operations (start to stop) from one set exercise versus instructor dependent resetting of exercises (i.e., stack clearing and riser killing are part of the same well control exercise)
2. Include more flexibility to circulation paths at BOP level (choke/kill lines, booster lines, etc.)
3. Provide three methods to determine choke and kill line friction pressures:
   - Standard circulating friction test (i.e., at different slow circulating rates pump down the string and take returns as normal up the riser. Then with an upper BOP closed and the choke and/or kill line(s) open, repeat circulating at same rates down the drill string and up the choke and/or kill line(s). The first series of pump pressure values are subtracted from the second set to determine frictional values. In addition, when circulating up the choke line, the student should be able to read choke line friction directly on the kill or monitor line gauge if valves are set properly.
   - With BOPs open and wellbore isolated, circulate at different slow pump rates down choke and/or kill line(s) while taking returns up the riser. Pump pressure is used as the frictional loss value.

- With BOP stack isolated (e.g., upper BOP closed, lower pipe ram closed) circulate down one choke/kill, and up another choke/kill line. (Dividing pump pressure by 2 gives the frictional loss value for a single choke or kill line.)

4. Ability to sweep gas from BOP stack after well kill (e.g., from isolated BOP stack cavity, displace choke/kill line with lighter density, reducing size/pressure of trapped gas)
5. Ability to open upper BOP to flush riser/BOP stack after well kill
6. Ability to kill the riser via a booster line prior to or after killing the wellbore
7. Ability to demonstrate on simulator space out and hang off procedure given a BOP configuration and heights to various stack components
8. Ability to demonstrate on simulator an emergency disconnect (i.e., cut and drop pipe and close well in prior to disconnecting)
9. Provide procedural and operational flexibility to circulate the choke and kill lines to break the gel prior to getting shut-in values and also prior to bringing the pump on line during the well kill (thereby minimizing ECD during start-up)
10. Ability to implement dynamic volumetric well control method
11. Ability to perform a LOT or FIT on simulator

5.3.5 Conclusions

Due to extreme depth and lower temperatures in the deepwater drilling environment, all manufacturers should validate the accuracy of simulation software for deepwater and ultra deepwater operations and responses, including the following:

- choke/kill friction and circulating friction responses
- additional calculations for viscosity and gel considerations
- response times for choke/pressure changes
- volume and pressure responses due to gas expansion

5.4 Deepwater Practical Well Control Training Guidelines

5.4.1 Summary

Practical training as accomplished today involves the use of physical simulators, but other options are being developed (e.g., interactive CDs). The following discussion is not written with the intent of precluding the use of the emerging technologies but to address the technologies in use to day, while providing guiding assistance concerning the direction of development for the developing technologies.

The practical guidelines stated are intended to enhance the current level of training and not to eliminate what is being taught. The guidelines are representative of the type training being completed in some cases, but provide new areas for focus as pertaining to deepwater drilling and well control. It is recognized that part of the practical training may have to be in the form of describing the procedure since all the necessary valving and equipment may not be on the simulator equipment.

5.4.2 Practical Training Guidelines/Student Skills

Students should demonstrate proficiency in the skills and procedures listed below.

Ability to line-up equipment to accomplish the following:

1. To determine choke line friction (3 methods)
2. To circulate the well through the riser
3. To circulate the well through the choke line
4. To circulate the riser with wellbore isolated (with and without the use of a booster line)
5. To circulate the choke and kill line (isolated from the wellbore and the riser)

6. To set-up the choke manifold to do the following:
   - Take returns up the choke and kill lines
   - Pump down the choke line the kill lines
   - Take returns through the bypass line for choke line friction
7. To engage the diverter system and divert either to the trip tank, the riser mud-gas separator, or the overboard lines
8. To accurately spot the tool joint within the BOP so as not to close a ram on a tool joint
9. To prepare for and implement an emergency disconnect

Ability to complete or identify the following:

1. Bring the pump on line and obtain choke line friction using choke, pump and kill line or monitor line pressures
2. Prepare and implement a well kill using the choke gauge and the ability to use the kill line or monitor line gauge
3. Implement a well kill using a normal circulation with consideration given to choke line friction (i.e., circulate down the drill pipe and up the choke line for a full circulation)
4. Break the well into its components and kill independently (Bring kill fluid up to the BOP, kill the isolated choke and kill lines, kill the BOP stack, and kill the isolated riser)
5. Line up and kill the well using the bullheading method (also know when to do this method)
6. Perform Driller's Method, Wait-and-Weight (Engineer's) method, and concurrent method of well control
7. Perform riser disconnect
8. Circulate the riser with diverter properly aligned
9. Space-out drill string prior to closing-in
10. Hang-off drill string with proper tensioning at surface to keep pipe in tension at stack for ease of cutting
11. Strip into the hole
12. Perform volumetric method of well control (inclusive of dynamic volumetric control; i.e., cross circulate choke

and kill lines while allowing gas to migrate up the hole while using shut-in drillpipe pressure to control BHP)

13. Be able to cross circulate the kill and choke lines.
14. Recognize underground flow or blowout
15. Control choke with compressible fluid in the hole (excessive lag times)
16. Take shut-in readings with compressible fluid(s) in the hole
17. Recognize the signs of a kick for both water based and compressible fluids (normal signs of kicks plus use of trends, use of PWD tools, etc.)
18. Determine shut-in DPP with float in string.
19. Compensate for increased gel strengths in the choke line due to temperature changes.
20. Identify when circulation through the choke line is not feasible.

5.4.3 Conclusions

Practical well control training is critically important in deepwater because of the lag times associated with compressible fluids and gel strengths resulting from extreme temperatures. Knowledge of these issues and how they relate to the reduced fracture equivalents is vital to a successful well kill. Knowledge and comfort with the needed skills are best reinforced with practice, allowing the individual to experience the results of actions taken, followed by options that may have proved more effective.

Those responsible for supervising well control operations in deepwater must have a working knowledge of concepts and procedures necessary for proper well control. Practice with simulators (inclusive of emerging technologies) is a must for these people so that deepwater well control concepts and procedures become second nature.

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