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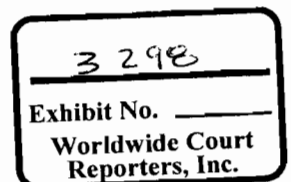
**Evaluation of Secondary
Intervention Methods in Well
Control**

For

U.S. Minerals Management Service

Solicitation 1435-01-01-RP-31174

March 2003



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18 March 2003

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**Subject: Evaluation of Secondary Intervention Methods
in Well Control**

Reference: Solicitation 1435-01-01-RP-31174

Dear Mr. Hauser:

Based on your previous comments we have prepared the final report for the research project "Evaluation of Secondary Intervention Methods in Well Control" as required by the contract for your review. Additional comments for clarity of the information and presentation are welcome.

If you have any technical questions about this report or its contents, please do not hesitate to call myself or Jeff Sattler for additional information. We look forward to seeing you in College Station on April 2nd. Thank you for the opportunity to provide the MMS with this research data and analysis.

Sincerely,

Raleigh S. Williamson, P.E.

Attachment:

Evaluation of Secondary Intervention Methods in Well Control

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1 Executive Summary

Secondary intervention can be defined as an alternate means to operate BOP functions in the event of total loss of the primary control system or to assist personnel during incidents of imminent equipment failure or well control problems. These systems can be completely independent and separate or utilize components of the primary BOP control system.

The design, capabilities, and early experiences of various secondary BOP (blowout preventer) control intervention systems as recently installed on twenty newbuild and upgraded drilling rigs were reviewed. Best systems and practices currently in use as well as opportunities that could enhance their effectiveness are presented.

Because of the variety and permutations of the systems installed on deepwater rigs, definitions (and critical terms) of the systems have been delineated in this study. Combinations of these systems are then evaluated. The secondary intervention systems defined and discussed herein are as follows:

- Deadman
- Automatic Mode Function
- Electro Hydraulic Backup
- Emergency Disconnect System
- Auto Disconnect
- Autoshear
- Acoustic System
- ROV Intervention

Selected regulatory body requirements and industry standards are reviewed and discussed herein. Requirements and standards reviewed include:

- 1) MMS regulations,
- 2) NPD regulations,
- 3) UK regulations,
- 4) API Specification 16D, 1st edition (*Specification for Control Systems for Drilling Well Control Equipment*),
- 5) NORSOK, and
- 6) IADC Deepwater Guidelines and IADC Deepwater Well Control Guidelines Supplement 2000.

Recommendations and mandates are correlated and analyzed for clarity, stringency, and effectiveness. Interpretation of these standards and regulatory documents was guided by the underlying intent of the documents while using common sense and placing the highest emphasis on environmental and safety issues.

Data for this study came from WEST assessments, supplemented by discussions with and review of documents from manufacturers of secondary intervention systems, operators, and drilling contractors.

Critical performance issues depend on two issues – type of control system (hydraulic or multiplex) and method of stationing over the well (anchored or dynamically positioned). The most important elements of a well designed secondary intervention system were defined as follows:

- Fast response
- Sufficient capacity
- Independence from primary system
- Environmentally independent
- Automatic activation by loss of hydraulic and electrical power to subsea stack
- Works in presence of mud plume or noise
- Contains well if LMRP accidentally disconnected and well kicks
- Manually secures non flowing well

For rigs with a multiplex BOP control system operating in DP mode, the recommended systems is a deadman system, with suggested enhancements noted in Section 6, to supplement the EDS system. For this type of control system operating in anchored mode, the EDS and auto disconnect systems can be eliminated or bypassed. In both cases, an ROV would be required to manually secure a non flowing well.

For rigs with hydraulic control systems, addition of an auto shear circuit is recommended to provide the automatic closure of the well in the event the LMRP is unlatched. Again, an ROV would be required to secure a non flowing well.

2 Introduction

2.1 Objectives

This research project provides a review of the design and capabilities of various secondary BOP (blowout preventer) intervention systems as recently installed on newbuild and significantly upgraded drilling rigs. In addition, it identifies the best systems and practices currently in use as well as opportunities that could enhance the effectiveness of these systems.

2.2 Overview

Secondary intervention can be described as an alternate means to operate BOP functions in the event of total loss of the primary control system or to assist personnel during incidents of imminent equipment failure or well control problems. A secondary intervention system can be completely independent and separate or utilize components of the primary BOP control system.

These systems are of the utmost importance and offer the last line of defense in preventing and/or minimizing environmental and safety incidents. An advanced knowledge of secondary intervention systems and their shortfalls could prevent an environmental event, human injuries, and/or loss of lives. Systems and practices vary considerably from rig to rig, geographic area and regulatory agency. Each system and practice currently in use that WEST has knowledge of was reviewed and evaluated in this study.

Secondary intervention systems currently in use can be generally categorized as follows:

1. Sequenced operation of multiple functions actuated
 - a. Automatically, or
 - b. Manually
2. Individual operation of selected functions.

Deepwater BOP functions are powered utilizing hydraulic fluid transported from a surface hydraulic system and most frequently augmented with fluid stored subsea. These functions are transmitted subsea using either electrical or hydraulic signals.

2.3 Categories and Brief Descriptions

Because of the variety and permutations of the systems installed on deepwater rigs recently put into service, it is important to define the meanings of each of the terms as used in this study. As noted above, they can be categorized and briefly described as follows:

Deadman

Application MUX, hydraulically piloted possible
Function sequence
Activation automatic, loss of electrical and hydraulic signals
Commonality independent

AMF (Automatic Mode Function)

Application MUX, hydraulically piloted possible
Function sequence
Activation automatic, loss of electrical and hydraulic signals
Commonality SEM (Subsea Electronics Module)

EHBU (Electro Hydraulic Backup)

Application MUX
Function sequence
Activation manual
Commonality MUX cables, solenoid valves, other

EDS (Emergency Disconnect System)

Application MUX
Function sequence
Activation automatic, watch circle
Commonality full

Auto Disconnect

Application hydraulically piloted, MUX possible
Function LMRP connector
Activation automatic, flex joint angle
Commonality independent

Autoshear

Application MUX, hydraulically piloted
Function shear
Activation automatic, LMRP separation
Commonality independent

Acoustic System

Application MUX, hydraulically piloted
Function discreet, several
Activation manual
Commonality independent

ROV Intervention

Application	hydraulic or MUX
Function	discreet, several
Activation	manual
Commonality	independent

While each of the major manufacturers have their own terms and descriptions of secondary intervention control systems, the above referenced terms are used throughout this paper with the definitions noted.

3 Terms and Definitions

3.1 Regulatory

3.1.1 MMS (Minerals Management Service)

The regulatory body that provides regulations for the oil industry in U.S. waters.

3.1.2 NPD (Norwegian Petroleum Directorate)

The regulatory body that provides regulations for the oil industry in the Norwegian sector of the North Sea.

3.1.3 HSE (Health and Safety Executive)

The regulatory body that provides regulations for the oil industry in the UK sector of the North Sea.

3.1.4 Department of Minerals and Petroleum Resources

The regulatory body that provides regulations for the oil industry in Australia.

3.2 Industry Bodies

3.2.1 API (American Petroleum Institute)

An American industry group comprised of operators, contractors, engineering companies and equipment suppliers. API generates recommended minimum practices for equipment and operations in addition to manufacturing specifications for equipment. This group has no regulatory powers. However, such standards have assumed regulatory status upon reference by others, including the MMS. Because of the cooperative efforts of the various groups associated with API, compliance with these standards provides a minimum baseline to which equipment and practices can be compared.

3.2.2 NORSOK (Norsk Søkkel Konkuranseposisjon or, in English, The Competitive Standing of the Norwegian Offshore Sector)

An initiative developed by Norwegian industry groups to reduce development and operations cost for the offshore oil and gas industry. As with the API, the group is comprised of operators, contractors, engineering companies and equipment suppliers. NORSOK generates recommended minimum practices for equipment and operations. This group does not have regulatory powers; however, as noted above, when their recommendations are referenced by regulatory bodies, including NPD, they assume regulatory status. As with the API, wide participation across industry groups allows some commonality and a standard of reference.

3.2.3 IADC (International Association of Drilling Contractors)

A group comprised primarily of owners of drilling rigs. The IADC develops and publishes additional standards that are accepted by operators and others to facilitate easy review of systems. These include drilling, safety, and training standards, among others.

1. 3.3 Terms

3.3.1 Equipment Description

3.3.1.1. Accumulators

Devices in hydraulic systems for the storage of hydraulic fluid at pressure, used on both the surface and subsea. Some accumulators on the subsea BOP stack are designated as system accumulators and are used to augment fluid supply during normal operations. They were originally designed to reduce the time to complete a control function (in compliance with regulations and/or standards, as well as operator requirements) as drilling rigs moved into deeper water. Others are circuit specific and are dedicated for use only in certain emergency operations.

3.3.1.2. LMRP - (Lower Marine Riser Package)

That portion of the stack containing the attachment point for the marine drilling riser. Primary components include the BOP control system pods, usually at least one, and sometimes two, annular preventer and a hydraulically operated connector. A critical reason for this arrangement is to allow remote disconnecting of the drilling rig from the BOP stack on the sea floor. The portion of the stack remaining on the wellhead, called the lower stack, contains the well while allowing rapid resumption of drilling upon resolution of the difficulty responsible for the disconnect, e.g. severe storm.

3.3.1.3. ROV (Remotely Operated Vehicle)

A submersible vessel whose movement is controlled via an electrical umbilical from the drilling rig. Depending upon the equipment installed and tools carried, typical functions are operation of certain hydraulic or mechanical BOP stack functions, surveillance, and replacement of gaskets subsea.

3.3.1.4. SEM (Subsea Electronics Module)

A one-atmosphere pressure vessel integrated into a Cameron MUX control pod containing circuit boards and other electronic components.

3.3.1.5. Spec –Specification

Utilized as a standard for manufacturing.

3.3.1.6. RP –Recommended Practice

Utilized by some as a standard for equipment and systems currently in service.

3.3.2 System Descriptors

Every secondary intervention system can be categorized according to four parameters. Each of those parameters is defined for the purposes of this report as follows.

3.3.2.1 Application

Two general types of control systems are used on floating drilling rigs.

3.3.2.1.1. Hydraulically piloted

Shallow water control system - use a hydraulic system for both the motive fluid as well as signal transmission. Signal transmission is accomplished by using hydraulic fluid to activate the pilot on a pod valve.

3.3.2.1.2. MUX (Multiplex)

When operating in deeper water, generally in excess of 3500 feet, the need for more rapid signal transmission necessitated the development of electrical systems. These systems utilize PLCs (Programmable Logic Controllers) to transmit the operator's action on a control panel to an electronic pulse that is transmitted subsea. Reliability has been enhanced by the use of multiple redundant PLCs driven by both custom and vendor supplied software. MUX systems have the added advantage of being able to utilize sequences and logic through custom programming.

3.3.2.2 Function

The action completed when the system is activated.

3.3.2.2.1. Sequence

A series of functions in a defined order. Included in the definition of each step is the specification of a time to be executed, allowing the designer to allow time lags for various purposes, the most common being the completion of a prior activity. Multiple sequences can be programmed, with an ability of the operator to select a given one to match the current drilling operation.

3.3.2.2.2. Discreet

This indicates a single function. Several functions can be activated, one at a time.

3.3.2.3 Activation

The method by which the secondary intervention is initiated.

3.3.2.3.1. Automatic

No operator intervention is required to begin this type of system. It should be noted that often automatic systems are inactivated until they are manually set, or armed.

3.3.2.3.2. Manual

Systems described by this term require the operator to complete an action or actions. Multiple simultaneous operations are often required to minimize accidental activation.

3.3.2.4 Commonality

The extent to which the secondary intervention system uses portions of the primary control system.

3.3.2.4.1. Independent

There are no components of the primary control system that are utilized when the secondary system is functioned, including signal transmission.

3.3.2.4.2. Dependent

Portions of the primary control system must be operational for the secondary system to complete its intended function.

3.3.3 Systems

It is becoming more common to find multiple secondary intervention systems “piggy backed” onto one another. While this may provide the operator with an expectation that loss of containment risks have been reduced, it can have the reverse effect if an in-depth circuit and risk analysis is not performed to determine how the systems could interact with each other and the methods of interfacing.

3.3.3.1 Deadman

A fully automatic control system that, when armed, will operate specified BOP stack functions in the event of a *catastrophic failure that includes total loss of signal communication and hydraulic supply from the surface*. The most common failure mode that is the basis for this actuation is complete parting of the riser string. Typically, this sequence operates only the blind shear rams and its locking system. If equipped, a casing shear ram function may be initiated first depending on current rig operations. *This is a stand-alone system* that does not share any components with the primary control system.

Because of this independence, the system requires the design and installation of dedicated subsea accumulators and hardware. Although it is typically found only on MUX control systems, it could be used on a conventional hydraulically piloted control system. All major manufacturers use this term.

3.3.3.2 AMF (Automatic Mode Function)

A fully automatic control system from Cameron that, when armed, will operate specified BOP stack functions in the event of a *catastrophic failure that includes total loss of signal communication and hydraulic supply from the surface*. Again, these were designed with parted riser as the most likely failure mode. *Not stand-alone systems*, AMFs utilize some of the same components used in the primary control system operations, including the SEM. Some independence is provided by installation of dedicated subsea accumulators, hardware, and software that can be programmed to operate several functions. *The number of functions that can be operated is limited only by the amount of fluid in the dedicated subsea accumulators*. Although it is typically found only on MUX control systems, it could be used on a conventional hydraulically piloted control system.

3.3.3.3 EHBU (Electro Hydraulic Backup)

An alternative control system from Varco Shaffer® that uses dedicated accumulators and provides a third level of *hard wired* redundancy for use *in the event of total primary system communication failure*. This is *not a stand-alone system*, but one that utilizes some of the same components used in primary control system operations, including the MUX cables and solenoid valves. The EHB backup system is found on older generation Shaffer MUX control systems, not in the newer fiber optic systems. This system was replaced on the new Varco Shaffer® MUX control systems with built in electronic redundancy both in the pods and in the Central Control Unit on the surface.

3.3.3.4 EDS (Emergency Disconnect System)

Also referred to as an Automatic or Emergency Quick Disconnect system, this system is part of the primary control system. An EDS is a sequence of functions that is initiated when the rig has moved significantly off location. *This failure mode is most often assumed by failure(s) in the DP system*. The EDS operates specified BOP stack functions in sequence, securing the well by shearing pipe and ending with the disconnection of the LMRP. Multiple sequences can be programmed, depending on the operating mode, e.g. adding the functioning of the casing shear ram. Because the programming is provided by the PLCs in the system, these are found only on MUX control systems.

3.3.3.5 Auto Disconnect

This *mechanically initiated system* utilizes dedicated accumulators on the LMRP to affect an emergency disconnect when the rig moves significantly off location. This system was installed on some rigs after a risk analysis demonstrated that the *wellhead would be the first to fail in case of a drift off combined with failure to disconnect*. Were the wellhead to be pulled out, the well would no longer be contained. After the system is enabled by the ROV subsea, a *mechanically operated* hydraulic pilot valve is tripped when the flex joint angle reaches a predetermined angle, initiating disconnect. *This system alone cannot provide wellbore containment*, but must be combined with an autoshear circuit. It is principally used on hydraulically piloted systems, but could be used on a MUX control system.

3.3.3.6 Autoshear

Autoshear is defined by the IADC as a *stand-alone system that automatically shuts in the wellbore upon an unplanned disconnect of the LMRP connector*. The Autoshear feature is a *stand alone system* that has two status modes: disarmed and armed. If armed, when the LMRP is separated from the stack, the Autoshear feature activates. Activation closes the shear rams and/or casing. Hydraulic power is obtained from lower BOP stack mounted accumulators. The Autoshear package is typically *mechanically activated* and uses an independent hydraulic control system. This system is used on both MUX and conventional hydraulically piloted control systems.

3.3.3.7 Acoustic System

A *stand alone* alternate control system that has the capability of operating discreet BOP stack functions from permanent and/or self-contained portable control units through the use of encoded acoustic signals transmitted through the water. The system requires dedicated subsea hardware, software, accumulators and hydrophones, and is installed on both MUX and conventional hydraulically piloted systems.

3.3.3.8 ROV Intervention

ROV intervention is a *stand alone system* that is the simplest and *most basic form of secondary intervention* and has been in use for many years. ROVs can be used to disconnect the LMRP riser connector, close and lock a ram, or operate any other function on the BOP stack provided that function has been equipped with the requisite ROV connection. It can also be used for mechanical operations such as replacing connector gaskets. For well control purposes, the *ROV is equipped with a hydraulic pump* and has the ability to insert a quick disconnect stab into a female receptacle connected directly to a function such as a ram BOP. While the ROV can be equipped with a hydraulic reservoir for lower volume functions, high volume functions such as rams are usually operated with seawater.

4 Applicable Regulatory Requirements and Industry Standards

Selected regulatory body requirements and industry standards are compared and contrasted herein. Requirements and standards reviewed include:

- 1) MMS regulations,
- 2) NPD regulations,
- 3) UK regulations,
- 4) API Specification 16D, 1st Edition (Specification for Control Systems for Drilling Well Control Equipment),
- 5) NORSOK,
- 6) IADC Deepwater Guidelines and IADC Deepwater Well Control Guidelines Supplement 2000.

WEST proprietary Inspection and Test Procedures, ITPs, are also referenced if significant additional information or guidelines are provided.

Recommendations and mandates are correlated and analyzed for clarity, stringency, and effectiveness. Capabilities of available secondary intervention technologies are compared.

In some cases, wording used in both regulatory documents and industry standards is unclear and can be interpreted in different ways. WEST has attempted to interpret these documents guided by the underlying intent of the documents while using common sense and placing the highest emphasis on environmental and safety issues.

The following is a brief overview of the various regulatory requirements, industry standards and what is considered good oilfield practice concerning secondary intervention. In many cases, the referenced statement is considered to apply to both routine operations and secondary intervention.

4.1 Secondary Intervention Systems General

Should the BOP stack experience a total loss of the primary control system, what would be the best secondary back-up methodology to operate the BOP functions to assist personnel during incidents of imminent equipment failure or well control problems? A secondary intervention system can be completely independent and separate or utilize components of the primary BOP control system. Different contractors and operators have offered different approaches in this area.

4.1.1 MMS

- 4.1.1.1 Regulation: CFR Title 30, Chapter II (7-1-01 Edition), Subpart A – General:250.107**
What must I do to protect health, safety, property, and the environment?
“(c) You must use the best available and safest technology (BAST) whenever practical on all exploration, development, and production operations. In general, we consider your compliance with MMS regulations to be the use of BAST.”
- 4.1.1.2 Regulation: CFR Title 30, Chapter II (7-1-01 Edition), Subpart D – Oil and Gas Drilling Operations: 250.401**
General requirements.
“The lessee shall utilize the best available and safest drilling technology in order to enhance the evaluation of conditions of abnormal pressure and to minimize the potential for the well to kick or flow. The lessee shall utilize equipment and materials necessary to assure the safety and protection of personnel, equipment, natural resources and the environment.”
- 4.1.1.3 Regulation: CFR Title 30, Chapter II (revised, 2-20-03), Subpart D – Oil and Gas Drilling Operations: 250.440**
Blowout preventer systems and system components.
“(a) General. The BOP systems and system components shall be designed, installed, used, maintained, and tested to ensure well control.”
- 4.1.1.4 Regulation: MMS Safety Alert No. 186, paragraph (5)**
“The MMS considers a backup BOP actuation system to be an essential component of a deepwater drilling system and, therefore, expects OCS operators to have reliable back-up systems for actuating the BOP in the event that the marine riser is damaged or accidentally disconnected.”
- 4.1.1.5 Interpretation:**
MMS requires the lessee to employ the Best Available and Safest Technology (BAST) to assure the safety and protection of personnel, equipment, natural resources and the environment. MMS considers secondary intervention systems to be an essential element of BAST.

4.1.2 NPD

Section 31

Requirements relating to blowout preventers with associated equipment.

“It follows from this provision that where the blowout preventer (BOP) has the function of a barrier, it must be designed in such a way as to ensure that the functioning of the valve as a barrier can be maintained.”

According to current practice this means that:

“m) when drilling with BOP installed on the sea bed, an acoustic or an alternative control system for operation of pipe ram preventers, shear ram preventer and connection for marine riser shall in addition be installed.”

4.1.3 UK

UK regulations are not specific in most cases, and rely on prudent and safe equipment maintenance by the contractor and safe operation by the operator. Due to this lack of specific regulations WEST conducts surveys in UK waters using API Specifications and Recommended Practices as guidelines for prudent operations and good oilfield practice.

The well operator is generally the petroleum company that operates the lease, and must ensure the following regulation is complied with.

Regulation 13: “General Duty”

(1) “The well-operator shall ensure that a well is so designed, modified, commissioned, constructed, equipped, operated, maintained, suspended and abandoned that - ”

(a) “so far as is reasonably practicable, there can be no unplanned escape of fluids from the well; and”

(b) “risks to the health and safety of persons from it or anything in it, or in strata to which it is connected, are as low as is reasonably practicable.”

4.1.4 API

4.1.4.1 Standard: Spec 16D, section 1.5

Emergency Backup BOP Control Systems

“When the subsea control system is inaccessible or nonfunctional, an independent control system may be used to operate critical well control and/or disconnect functions. These systems have their own supply of power fluid. They include acoustic control systems, ROV (Remotely Operated Vehicle) operated control systems and LMRP recovery systems.”

4.1.4.2 Interpretation:

By use of the word “may”, API refers to emergency back-up BOP control systems as optional equipment.

4.1.5 NORSOK

NORSOK Standard

Drilling Facilities

D-001, Rev. 2, July 1998

5.10.3.8 Special requirements for MODUs

“Pressure regulators in the system shall remain unaffected in the event of loss of power supply, e.g. loss of compressed air.”

3. *“When drilling with the BOP system installed on the seabed, an acoustic or an alternative control system shall in addition be installed.”*

4.1.6 IADC

Unplanned Disconnects

In Deepwater Drilling

Prevention Measures and Emergency Response

“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.”

4.1.7 Discussion:

Secondary intervention (back-up BOP actuation) systems are a required component of subsea blowout prevention systems per MMS best available and safest technology philosophy. MMS Safety Alert No. 186 clouds this requirement by using the term “deepwater” instead of subsea when referring to drilling systems applicable to the alert. The alert does require OCS operators to have reliable back-up systems for actuating the BOP in the event that the marine riser is damaged or accidentally disconnected. Marine riser is inherent to all subsea BOPs.

Clarification of deepwater as opposed to “non-deepwater” drilling systems should be made. API makes no requirement for secondary intervention systems for BOP actuation.

A multi-function ROV secondary operating system operating panel should be mounted in an accessible location on the BOP stack and the panel should be clearly labeled for identification by the ROV television cameras.

If an ROV system is in use, it is clear that the ROV should be able to locate the interface panel and be able to discriminate between several functions, but this is not always the case. Frequently there will be three or four hot stabs lined up in a row and no way for the ROV pilot to determine which stab operates what function. Often, these functions are not routinely tested on the surface and few drawings exist.

Performing a wellbore test after actuating the BOP with the backup system best proves the reliability of the function.

An ROV operated glycol injection system for the wellhead connector should be installed if hydrates are present. This is recommended as good oilfield practice.

4.2 Shear Ram Capabilities and Operating Pressure:

The ultimate success of the secondary intervention system is completely dependent upon the ability of the shear ram to shear the drill pipe used under the specific well conditions experienced. Thus, it is prudent to understand the pressure at which the shear rams shear/seal the drill pipe. The ability to deliver the pressure required to shear the pipe at depth and with the mud used is most critical.

4.2.1 Operating Pressure Requirements

4.2.1.1 MMS

New MMS regulation 30 CFR Part 250.416(e) requires the lessee to provide information that shows that the blind-shear or shear rams installed in the BOP stack (both surface and subsea stacks) are capable of shearing the drill pipe in the hole under maximum anticipated surface pressures.

4.2.1.2 NPD

4.2.1.2.1 Regulation: Section 26 paragraph 1

Design assumptions for drilling and well control equipment

"A barrier philosophy for each individual operation planned to be carried out from a facility shall be established at an early stage of the design phase. Functional requirements shall be defined with regard to the drilling and well control equipment's suitability, operative capability and ability for mobilization for compliance with the barrier philosophy. All systems and components shall meet these requirements."

4.2.1.2.2 Regulation: Section 26 paragraph 2

Design assumptions for drilling and well control equipment

"Pursuant to section 26, 6th paragraph of the regulations, it will not be possible to comply with all of these requirements for all types of equipment, for example, certain parts of the bottom hole assembly (BHA) will be unable to be cut by the BOP shear ram."

4.2.1.2.3 Regulation: Guidelines, section, 31 Paragraph j

"The acoustic accumulator unit shall have sufficient pressure for cutting the drillstring, after having closed a pipe ram preventer. In addition, the pressure shall be sufficient to carry out disconnection of the riser package (LMRP) after cutting of the drillstring has been completed."

4.2.1.3 UK

See Section 4.1.3

4.2.1.4 API

4.2.1.4.1 Standard: Spec 16A, section 7.5.8.7.4

“Each preventer equipped with shear-blind rams shall be subjected to a shearing test. As a minimum, this test requires shearing of drill pipe as follows: 3 1/2-inch 13.3 lb/ft Grade E for 7 1/16-inch BOPs, 5-inch 19.5 lb/ft Grade E for 11-inch BOPs and 5-inch 19.5 lb/ft Grade G for 13 5/8-inch and larger BOPs. These tests shall be performed without tension in the pipe and with zero wellbore pressure. Shearing and sealing shall be achieved in a single operation. The piston closing pressure shall not exceed the manufacturer’s rated working pressure for the operating system.”

4.2.1.4.2 Standard: RP 53, section 13.3.2

“Note: The capability of the shear ram preventer and the operator should be verified with the equipment manufacturer for the planned drill string. The design of the shear BOP and or metallurgical differences among drill pipe manufacturers may necessitate high closing pressure for shear operations.”

4.2.1.5 NORSOK

4.2.1.5.1 Standard: Section 5.10.3.1

Blow Out Preventer (BOP). The shear ram shall be capable of shearing the pipe “*body of the highest grade drillpipe in use, as well as closing off the wellbore.*”

4.2.1.6 IADC

See Section 4.1.3

4.2.1.7 Interpretation, all referenced regulatory requirements and standards:

The shear rams shall be qualified to shear all items passing through the BOP stack, except the bottom hole assembly. Shearing capability is related to the hydraulic pressure available to the rams. The shearing capability of the shear rams must be documented to assure that it is appropriate for the grades and weights of pipe(s) in use. (Note that drill collars and casing cannot be sheared by standard shear rams.)

4.2.1.8 Discussion:

The operating pressure required to shear the drill pipe at depth and with maximum mud weight in the hole should be determined. The ROV should be capable of generating this amount of pressure plus a suitable safety factor. This safety factor is not listed in any of the referenced documents.

4.2.1.9 Internal WEST References

WEST ITP # 68, Effects of Wellbore Pressure on Closing Rams

Paragraph 1

The effects of the pressure in the wellbore are not always considered or understood *“when determining the pressures required to shear pipe or just to close a set of pipe rams. The effects can be bad enough to cause the inability to shear pipe in a well control situation. The same applies, to a lesser extent, to closing pipe rams.”*

4.2.2 Barrier Effectiveness

4.2.2.1 MMS

BUREAU OF LAND MANAGEMENT

43 FR PART 3160

Federal Register / Vol. 53, No. 223

III. Requirements

Well Control Requirements

1. “Blowout preventer (BOP) and related equipment (BOPE) shall be installed, used, maintained, and tested in a manner necessary to assure well control and shall be in place and operational prior to drilling the surface casing shoe unless otherwise approved by the APD.”

4.2.2.2 NPD

Guidelines, section 31 paragraph 1, m

Requirements relating to blowout preventers with associated equipment

1) "It follows from this provision that where the blowout preventer (BOP) has the function of a barrier, it must be designed in such a way as to ensure that the functioning of the valve as a barrier can be maintained. This also comprises the necessary functions connected with reestablishing a barrier, in that it shall be possible to carry out controlled circulation of fluid and gas out of the system, and allow fluid to be pumped in."

m) "When drilling with BOP installed on the seabed, an acoustic or an alternative control system for operation of pipe ram preventers, shear ram preventer and connection for marine riser shall in addition be installed."

4.2.2.3 UK

See Section 4.1.3

4.2.2.4 API

Standard: RP 53, section 18.3.3

"Pressure tests on the well control equipment should be conducted at least:

- a. "Prior to running the BOP subsea and upon installation."*
- b. "After the disconnection or repair of any pressure containment seal in the BOP stack, choke line, choke manifold, or wellhead assembly, but limited to the affected component."*
- c. "Not to exceed 21 days."*

4.2.2.5 NORSOK

NORSOK STANDARD

SUBSEA PRODUCTION SYSTEMS

U-001

Rev. 2, June 1998

5.2 Procedures/limitations for the operations

"The subsea system design work should include the definition of procedures/limitations for major operational modes, including installation and abandonment."

c. Normal Production

"This mode will include regular remote pressure testing of subsea barriers and routine inspection and maintenance by ROV, and well rate testing."

4.2.2.6 IADC

IADC references various portions of API RP 53, including 18.3.2 which says in part *“All blowout prevention components that may be exposed to well pressure should be tested first to a low pressure of 200 to 300 psi and then to a high pressure”*.

4.2.2.7 Interpretation:

The BOP stack shall be configured such that the well control circulation can be conducted with the drill string hung-off and the shear rams closed. Absent specific references to the contrary, this would be expected to apply to both the main control system and secondary system(s). Currently, secondary control systems do not control failsafe valves, disallowing circulation with these systems.

4.3 Response Time:

Response time is an issue because well control events start slowly and if handled early can be more readily controlled. Waiting too long allows the flow rates to increase vehemently, which can wash out and damage the BOP equipment—decreasing the likelihood of being able to close in the well.

4.3.1 MMS

New MMS regulation 30 CFR Part 250.442(c) requires that the accumulator system must meet or exceed the provisions of Section 13.3 of API RP 53.

4.3.2 NPD

4.3.2.1 Regulation

Guidelines, section 31 paragraph k, l

k) “response time for closing of BOP, when located on the seabed, will be up to 45 seconds. Response time refers to the time it takes from when the closing functions are activated from the panel until the BOP is in closed position”

l) “corresponding response time when the BOP is located on the installation is 30 seconds. (In the case of annular preventers exceeding 20" however, the response time may be up to 45 seconds)”

4.3.2.2 Interpretation:

The response time for closing both annular and ram type preventers shall be 45 seconds or less when stack is on the seabed and 30 seconds or less when they are on the rig in sizes less than 20" bore.

4.3.3 UK

See Section 4.1.3

4.3.4 API

4.3.4.1 Standard

Spec 16D, section 2.2.2.1

Response Time

“The control system for a subsea BOP stack shall be capable of closing each ram BOP in 45 seconds or less. Closing response time shall not exceed 60 seconds for annular BOPs. Operating response time for choke and kill valves (either open or close) shall not exceed the minimum observed ram close response time. The response time to unlatch the LMRP shall not exceed 45 seconds. Conventional measurement of response time begins when the function is activated at any control panel and ends when the readback pressure gauge recovers to its nominal setting.”

“Conformance with response time specifications may be demonstrated by manufacturer’s calculations, by simulated physical testing or by interface with the actual BOP stack.”

4.3.4.2 Interpretation:

Verify that the control system for a subsea BOP stack is capable of closing each ram BOP in 45 seconds or less and each annular in 60 seconds or less.

4.3.5 NORSOK

4.3.5.1 Regulation

5.10.3.8

Special requirements for MODUs

“Maximum response time for closing of BOP when located on the seabed, can be up to 45 seconds. Response time refers to the time it takes from the closing function is activated from the panel, until the BOP function is in closed position.”

4.3.5.2 Interpretation:

The response time for closing both annular and ram type preventers shall be 45 seconds or less when stack is on the seabed.

4.3.6 IADC

4.3.6.1 Regulation

Chapter K2, section B.1

"The control system for a subsea BOP stack should be capable of closing each ram BOP in 45 seconds or less. Closing response time should not exceed 60 seconds for annular BOPs. Operating response time for choke and kill valves (either open or close) should not exceed the minimum observed ram response time. Time to unlatch the LMRP should not exceed 45 seconds."

"Measurement of response time begins at pushing the button or turning the control valve handle to operate the function and ends when the BOP or choke or kill valve is closed effecting a seal, or when the hydraulic connector(s) is fully unlatched."

4.3.6.2 Interpretation:

The response time for closing rams is less than 45 seconds and less than 60 seconds for annulars. The response time for opening or closing choke or kill valves or to fully unlatch the LMRP connector should not exceed 45 seconds.

4.3.7 Discussion:

The above references do not specifically mention ROVs; nonetheless, since they are a secondary system and an integral part of the control system, they should be specifically addressed. WEST is of the opinion that they should be subject to the same requirements if they are to be effective in a well control event. Currently, ROV pumping capacities are not taken into consideration as it is usually assumed that the ram will only be operated in non-flowing conditions.

The pumping capacity of all ROVs is extremely limited, usually just a few gallons per minute. Ten to twenty minutes can be required to close a single ram, depending on the particular pump involved. Closing a ram BOP with a low volume hydraulic source while a well is flowing would almost certainly result in damage to the sealing components of the ram and would not be able to seal the wellbore. Thus, the ROV is in effect not a viable secondary intervention tool in a well control scenario.

4.4 Function/Pressure Tests:

Function/pressure tests are performed routinely to prove that the BOP stack works properly. The most critical secondary intervention system should probably receive the same attention to verify functionality if needed.

4.4.1 MMS

BUREAU OF LAND MANAGEMENT
43 FR PART 3160

Requirements

Well Control Requirements

1. *“Blowout preventer (BOP) and related equipment (BOPF) shall be installed, used, maintained, and tested in a manner necessary to assure well control and shall be in place and operational prior to drilling the surface casing shoe unless otherwise approved by the APD.”*

4.4.2 NPD

Section 31

Requirements relating to blowout preventers with associated equipment

“It follows from this provision that where the blowout preventer (BOP) has the function of a barrier, it must be designed in such a way as to ensure that the functioning of the valve as a barrier can be maintained.”

4.4.3 UK

See Section 4.1.3

4.4.4 API

RP 53, section 18.3.1

Function Tests

“All operational components of the BOP equipment systems should be functioned at least once a week to verify the component’s intended operations. Function tests may or may not include pressure tests. Function tests should be alternated from the driller’s panel and from mini-remote panels.”

4.4.5 NORSOK

5.2 Procedures/limitations for the operations

- c. *“This mode will include regular remote pressure testing of subsea barriers and routine inspection and maintenance by ROV, and well rate testing.”*

4.4.6 IADC

Draft Revisions to IADC Deepwater Well Control Guidelines, Page 17 Paragraph 3.

"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."

4.4.7 Interpretation, all referenced standards:

Function test the secondary intervention circuits as applicable. Wellbore pressure test each component, as applicable, after the secondary system has been activated. This is especially critical concerning the shear rams. Such a test sequence will prove the secondary system is capable of securing the well.

4.4.8 Discussion:

The ability of an ROV to close a ram BOP alone is insufficient. Many BOPs have locks that are independently functioned. In order to properly secure the well, the ROV must be able to maintain closing pressure on the ram while simultaneously engaging the locks. The only way to prove that the ROV has supplied sufficient pressure to both functions is to perform a wellbore test with all hydraulic pressure to the close and lock chambers vented.

4.4.9 Internal WEST Reference

WEST ITP #47, ROV Intervention, Paragraph 2:

"In subsea work the primary consideration is to keep the subsea equipment simple. A trade-off exists in BOP operations when ROVs are utilized. In the event of an unforeseen control systems failure the ROV allows an additional method of operating selected stack functions. This added versatility is gained at the expense of increased subsea complexity of the control system along with the increased cost of the added ROV functions. Function test the secondary intervention circuits as applicable. Wellbore pressure test each component as applicable, after the secondary system has been activated. This is especially critical concerning the shear rams and will prove the secondary system is capable of securing the well."

4.5 Single Point Failures:

Redundant systems are fundamental in controlling a drilling operation. For example, mud weight is the first round of defense against a kick, followed up by annulars and BOP rams and ultimately the sealing shear ram. A single point failure is an individual component failure that, if inoperable, will cause a function to become inoperable from multiple sources. Minimizing single point failures is a good oilfield practice that results in fewer well control events.

4.5.1 MMS

MMS 30 CFR Part 250.442d requires the use of dual control pods for subsea BOP stacks.

4.5.2 NPD

WEST was unable to locate NPD regulations pertaining to this issue.

4.5.3 UK

See Section 4.1.3

4.5.4 API

Spec 16D, section 2.2.2.6 paragraph 9

Control Manifold

“The control manifold interface shall be designed so that all control signals and power fluid supplies have redundant access (two separate jumpers, umbilical hose bundles, reels and control pods) to the shuttle valves on the BOP stack functions. Each retrievable pod shall be individually retrievable to the surface without loss of operability of any of the BOP stack functions through the other pod.”

RP 53, section 13.1 paragraph 1

General

“In addition to the equipment used for surface mounted BOP stacks, subsea control systems utilize pilot signals and readbacks that are transmitted to and received from subsea control valves in order to effect control of the subsea BOP. Dual controls are typical for increased reliability to transmit hydraulic supply power fluid subsea. Two independent pilot signal transmission/readback means are provided to control the two subsea control pods mounted on the lower marine riser package (LMRP). Both the control pods house pilot operated control valved for directing power fluid to and readback from the BOP stack.”

4.5.5 NORSOK

WEST was unable to find specific NORSOK regulations pertaining to this issue.

4.5.6 IADC

WEST was unable to find specific IADC regulations pertaining to this issue.

4.5.7 Interpretation, referenced standard:

Required redundancy is compromised by single point failures, commonly hose and/or shuttle valve placement.

4.5.8 Discussion:

The redundancy of the secondary system is invalidated if component failures that render the primary system inoperative prevents operation of the backup system; for example, should the pods be inoperable in a deadman system, type AMF deadman will also be inoperable. Hydraulic hoses are far more prone to failure than heavy wall pipe; thus they are a category for concern. Consideration should be given to the modification or replacement of hose with hard piping for improved reliability as practical.

4.6 Accumulators:

Useable volume, available pressure at depth and dependability are critical for secondary intervention systems should a well control event be experienced. For example, when shear rams are necessary to control a well, assurance that the accumulators will be able to shear and seal the well is needed. Adding complexity is the reality that Boyle's Law (Ideal Gas Law) is not a good predictor of the physical reality at depths exceeding 5,000 feet.

4.6.1 Useable Volume of Control System Fluid

4.6.1.1 MMS

New MMS 30 CFR 250.442(c) requires for subsea stacks that:
"the accumulator system equipment must meet or exceed the provisions of API RP 53, Section 13.3, Accumulator Volumetric Capacity."

4.6.1.2 NPD

Guidelines, section 31, Requirements relating to blowout preventers with associated equipment paragraph j

"when calculating accumulator capacity for BOP on the seabed, corrections must be made for hydrostatic pressure of a sea water column, as well as for sea temperature;"

Guidelines, section 31 paragraph m

"Accumulator unit 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."

4.6.1.3 UK

See Section 4.1.3

4.6.1.4 API

Spec 16D, section 2.2.2.5

Calculated Accumulator Volumetric Capacity Requirements

“The hydraulic control system for a subsea BOP stack shall have a minimum total stored hydraulic fluid volume, with the pumps inoperative, to satisfy the greater of the following requirements:”

1. *“Open and close, at zero wellbore pressure, all of the ram type BOPs and one annular BOP in the BOP stack, with fifty percent reserve ”*
2. *“The pressure of the remaining stored accumulator volume after opening and closing all of the ram BOPs and one annular BOP, shall exceed the calculated minimum system operating pressure. The calculated minimum system operating pressure shall exceed the greater of the following minimum stack component operating pressures:”*
 1. *“The minimum calculated operating pressure required (using the closing ratio) to close any ram BOP (excluding shearing pipe) at the maximum rated wellbore pressure of the stack.”*
 2. *“The minimum calculated operating pressure required to open and hold open any choke or kill valve in the stack at the maximum rated wellbore pressure of the stack.”*

RP 53, section 13.3.2

“BOP systems should have sufficient usable hydraulic fluid volume (with pumps inoperative) to close and open one annular-type preventer and all ram-type preventer from a full-open position against zero wellbore pressure. After closing and opening one annular preventer and all ram-type preventers, the remaining pressure shall be 200 psi (1.38 Mpa) or more above the minimum recommended precharge pressure.”

4.6.1.5 NORSOK

Section 5.10.3.7

BOP Control System

“The accumulator capacity for operating a BOP stack with associated systems shall have as a minimum sufficient volumetric capacity to close, open and close all the installed BOP functions, plus 25 per cent of the volume for one closing operation for each one of the said BOP rams.”

4.6.1.6 IADC

Chapter K2, section B.1

Accumulator Volumetric Capacity Calculation

"The accumulator volumetric capacity is sized to the requirements of the individual BOP stack to be controlled...."

"Note: The minimum performance and capacities recommendations for subsea BOP well drilling control systems is as listed in API RP 16E, latest edition."

Note that API RP 16E has been repealed.

4.6.1.7 Interpretation of all regulations and standards:

Major regulations and standards (see table attached) have a means to determine the minimum usable fluid for the functioning of the BOP stack from the surface. Key issues addressed by these references are volumetric safety factors, albeit indirectly, and calculation techniques. Minimal guidelines exist to determine appropriate usable volumes for secondary intervention systems. If the riser parts or communication to the stack is broken, the usable fluid available to the secondary intervention systems becomes an extremely important factor. The last line of defense may not be able to operate if there is not enough usable accumulator volume to function the equipment.

Regulations and standards do not address useable volumetric requirements for secondary intervention systems directly. Several reference documents discuss computational corrections for depth, which could be used for secondary systems.

Table 1
BOP Accumulator Capacity and Response Times for Subsea Stacks

METHOD OF CALCULATION	RESPONSE TIME	ACCUMULATOR CAPACITY
API RP-53 3 rd Edition Section 13.3.5	Rams < 45 sec. Annulars < 60 sec.	Close + Open All Rams and 1 Annular Acc Press > Precharge + 200 psi
<i>Spec 16D</i> 1 st Edition Section 2.2.2.5	Rams < 45 sec Annulars < 60 sec C/K Valves < Rams Times	Close + Open All rams and 1 Annular + 50% Vol. Reserve Acc Press > Precharge And Close + Open All Rams and 1 Annular Acc Press > min press to operate Ram using Operating Ratio at MWP or Valve using Operating Ratio at MWP, whichever is greater.
USA MMS 2000 30 CFR, Ch. II 250.406(d)(1)		Close all BOP Equipment + 50% Vol. Reserve Acc Press > Precharge + 200 psi
NORWEGIAN NPD 1999 YA-001A, Drilling Installation and Equipment Section 31	Closing of BOP < 45 sec.	Close 2 Pipe Rams + 1 Shear Ram + Unlatch LMRP Connector + 50% Vol. Reserve
Norsok Section 5.10.3.7	Closing of BOP < 45 sec.	Close + Open + Close of all BOP equipment + 25% Vol. to close all rams
IADC Chapter K2 Section B.1	Rams < 45 sec. Annulars < 60 sec. C/K Valves < Rams Times Unlatch the LMRP connector < 45 sec.	(See API Spec 16D)

NOTE:

- < means "less than"
- > means "greater than"
- WBP means Wellbore Pressure

4.6.1.8 Discussion:

Useable volume is particularly important on secondary intervention systems, insofar as inadequate energy to execute the required function or sequence renders the system useless. Currently, systems are designed using a variety of safety factors concerning volumetric requirements.

Only NPD addresses useable volume for one particular type of secondary intervention. NPD specifically states the functions that must be operated by the acoustic system using the accumulator volume

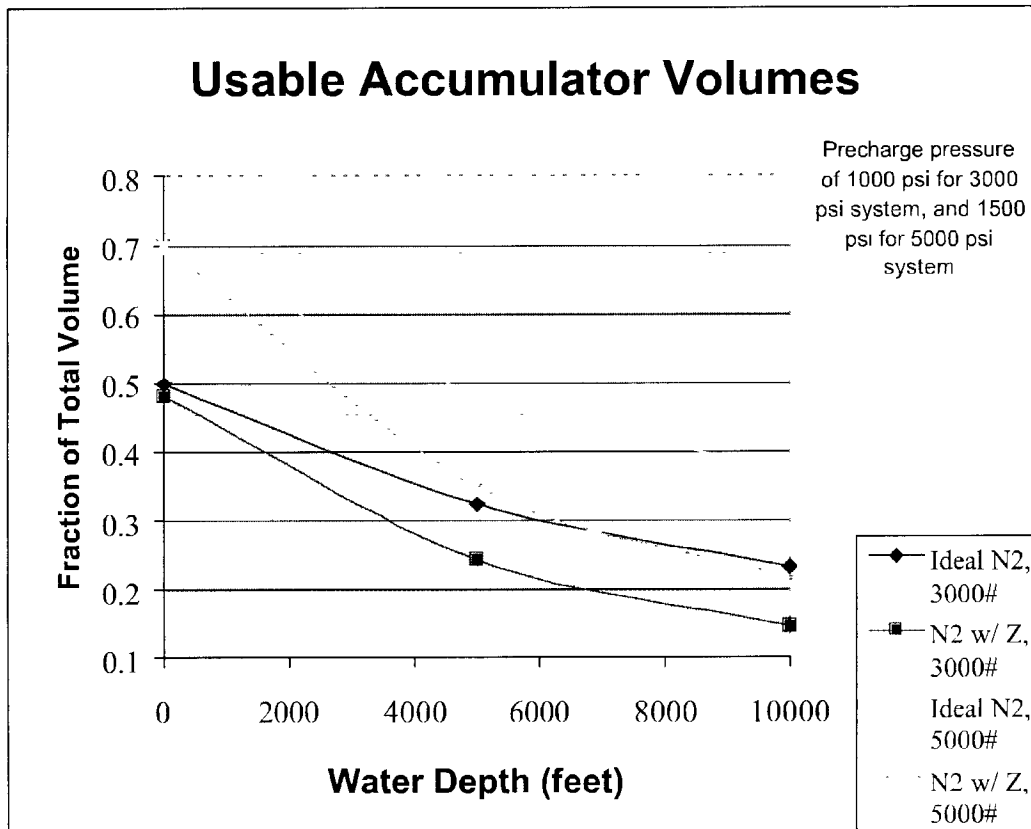
Once desired volumetric requirements are decided, operating variables and computational techniques are selected. Of the many variables in calculating useable volume in stack mounted accumulators, precharge and operating depth are critical. Accumulator volume calculations in use today as recommended by MMS and API rely on the ideal gas law. Computing volumes based on ideal gas law results in substantial error when used in water depth greater than 5000 feet (see attached graph). This error is exacerbated by newer systems' control pressure of 5000 psi.

Standards for secondary intervention hydraulic design would be useful in the areas of

- Volumetric safety factor,
- Recommended calculations for pressure and depth corrections, and
- Precharge and minimum pressures.

An additional safety concern is the pressure rating for accumulators considering new depth requirements.

Figure 1
Usable Accumulator Volumes



4.6.2 Reliability

4.6.2.1 MMS

MMS does not specifically address accumulators used for secondary intervention systems, but according to: MMS CFR Title 30, Section 250.440(c):

You must design, install, maintain, test, and use the BOP system and system components to ensure well control. The working-pressure rating of each BOP component must exceed maximum anticipated surface pressures. The BOP system includes the BOP stack and associated BOP systems and equipment.

And

The accumulator system must meet or exceed the provisions of Section 13.3, Accumulator Volumetric Capacity, in API RP 53, Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells.

4.6.2.2 NPD

Re. Section 31

Requirements relating to blowout preventers with associated equipment

"It follows from this provision that where the blowout preventer (BOP) has the function of a barrier, it must be designed in such a way as to ensure that the functioning of the valve as a barrier can be maintained."

m) "when drilling with BOP installed on the sea bed, an acoustic or an alternative control system for operation of pipe ram preventers, shear ram preventer and connection for marine riser shall in addition be installed."

4.6.2.3 UK

See Section 4.1.3

4.6.2.4 API

Spec 16D, section 2.2.2.6 paragraph 9

Control Manifold.

"The control manifold interface shall be designed so that all control signals and power fluid supplies have redundant access (two separate jumpers, umbilical hose bundles, reels and control pods) to the shuttle valves on the BOP stack functions."

RP 53, section 13.3.4

Subsea accumulators shall have isolation and dumping capabilities.

4.6.2.5 NORSOK

WEST could not locate a reference from NORSOK pertaining to accumulator reliability.

4.6.2.6 IADC

WEST could not locate a reference from IADC pertaining to accumulator reliability.

4.6.2.7 Interpretation of referenced standard:

Again, the principle of redundancy is expressed without being specific.

4.6.2.8 Discussion:

In most modern control systems there are single valves, typically identified as conduit flush and accumulator dump, on the LMRP that do not have redundancy. Should these valves fail, system pressure would be lost. The least expensive method of establishing redundancy is to install an ROV operated ball valve downstream of the valve.

Isolation of accumulator banks allows the minimization of lost capability upon failures of individual components. Accumulator dumping capabilities are required such that pressurized vessels are not brought to the surface where their pressure ratings may be exceeded. Redundancy of both systems can be improved with ROV capabilities.

4.7 Acoustic Systems:

The relevant issue is whether or not the acoustic system will be able to secure the well should there be a well control situation. Currently acoustic systems are required in Norway and Brazil with the biggest problem noted by drilling contractors being subsea noise interfering with the acoustic signal from the surface.

4.7.1 MMS

Although there are no specific MMS regulations pertaining to acoustic systems, MMS Safety Alert No. 186 states that a backup BOP actuation system should be considered an essential component of a deepwater drilling system and, therefore, expects OCS operators to have reliable back-up systems for actuating the BOP in the event that the marine riser is damaged or accidentally disconnected.

4.7.2 NPD

4.7.2.1 Regulation

Guidelines, section 31 paragraph m

"When drilling with BOP installed on the seabed, an acoustic or an alternative control system for operation of pipe ram preventers, shear ram preventer and connection for marine riser shall in addition be installed."

"The acoustic accumulator unit shall have sufficient pressure for cutting the drillstring, after having closed a pipe ram preventer. In addition, the pressure shall be sufficient to carry out disconnection of the riser package (LMRP) after cutting of the drillstring has been completed. A portable unit, which can be handled by one person, shall be available for operation of the abovementioned functions in the event of evacuation from the platform."

4.7.2.2 Interpretations

4.7.2.2.1 Capabilities

An acoustic or an alternate control system shall be available to operate the pipe rams, shear rams and LMRP connector unlock.

4.7.2.2.2 Activation Unit Requirement

A portable unit that can be handled by one person shall be available to operate the acoustic or alternate control system in case of rig evacuation.

4.7.2.2.3 Accumulator Capacity

The acoustic system accumulators shall have sufficient capacity (volume) to close two pipe rams, close the shear rams and unlock the LMRP connector, plus 50%.

4.7.2.2.4 Pressure Requirements

The acoustic system shall have sufficient pressure for shearing the drill pipe after closing a pipe ram preventer and unlocking the LMRP connector.

4.7.3 UK

See Section 4.1.3

4.7.4 API

WEST could not find specific API regulations pertaining to this issue.

4.7.5 NORSOK

D-001, Rev. 2, July 1998

Section 5.10.38 - Special requirements for MODUs

“With regard to floating offshore units with BOP located on the sea bed, there shall in addition be sufficient remaining pressure to enable the LMRP to be disconnected after completion of cutting the drillstring.”

“Pressure regulators in the system shall remain unaffected in the event of loss of power supply, e.g. loss of compressed air.”

3. *“When drilling with the BOP system installed on the seabed, an acoustic or an alternative control system shall in addition be installed.”*

4.7.6 IADC

The IADC does not specifically address acoustic systems, however their publication entitled *“Unplanned Disconnects In Deepwater Drilling, Prevention Measures and Emergency Response”* discusses technical issues regarding acoustic systems.

4.7.7 Discussion:

Minimum functional requirements as defined in the NPD regulations could also be used to define minimum ROV requirements. Additional minimum ROV requirements could be added, such as backup valves for potential single point failures. Also, note that in the absence of specifications or recommendations for volume requirements of dedicated accumulators for deadman type systems, these same specifications can be applied.

Personnel Qualifications:

When and how to operate the secondary intervention system on a given vessel is critical; it goes without saying that having a system in place is of little value if key staff are not knowledgeable about how to operate it in a short timeframe.

4.8.1 MMS

4.8.1.1 Regulation: CFR Title 30, Volume 2, (revised, 2-20-03), Subpart D – Oil and Gas Drilling Operations: section 250.401 (d)

What must I do to keep wells under control?

“Use personnel trained according to Subpart O...”

4.8.1.2 Interpretation:

MMS requires the lessee to establish standards of training and competency of all personnel involved in oil and gas drilling operations.

4.8.2 NPD

4.8.2.1 Regulation: Section 18 and NPD Guidelines to regulations relating to drilling, 1999, section 18.

Paragraph 1

“Personnel engaged in planning, implementation and verification of drilling and well operations shall have the necessary qualifications. The operator shall stipulate qualification requirements in the form of theoretical and practical training in respect of all positions of significance to safety.”

Paragraph 4

“Requirements to personnel qualifications are also applicable to contractors, sub-contractors and suppliers with independent contractual work in the activities. Requirements relating to job categories shall be established both for shore-based personnel and for the personnel on board the installation.”

“A recognized standard for qualifications of personnel carrying out NDE examinations of drilling equipment, reference is made to requirements contained in Regulations relating to load bearing structures, issued by the Norwegian Petroleum Directorate 7 February 1992.”

4.8.2.2 Interpretation:

NPD requires the operator is to establish qualification and training requirements for all contractors, subcontractors and suppliers to assure safe performance of all task(s) required in drilling and well operations.

4.8.3 UK

See Section 4.3.1

4.8.4 API

WEST could not locate a reference from API pertaining to Personnel Qualifications.

4.8.5 NORSOK

WEST could not locate a reference from NORSOK pertaining to Personnel Qualifications.

4.8.6 IADC

WEST could not locate a reference from IADC pertaining to Personnel Qualifications.

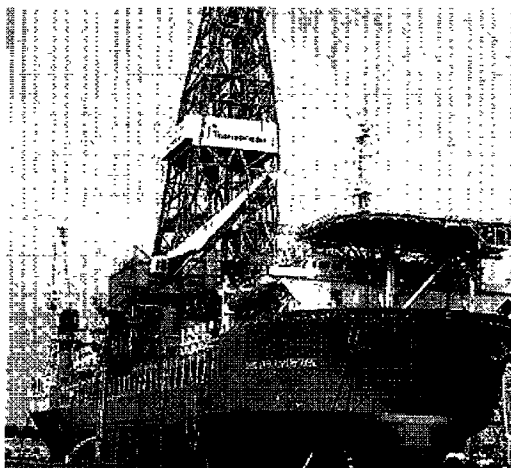
4.8.7 Discussion:

Personnel competency requirements for the operation and maintenance of secondary intervention systems available on a particular vessel are generally specified by joint arrangement between the operator and contractor but there are no certification requirements.

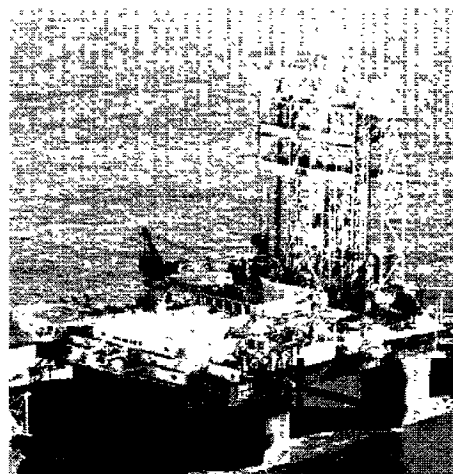
There are no certification requirements for ROV pilots or supervisory personnel. ROV personnel competency requirements are generally specified by the individual ROV company with little outside interference from operators unless performance is considered below average.

5 Secondary Intervention Systems In Use Today

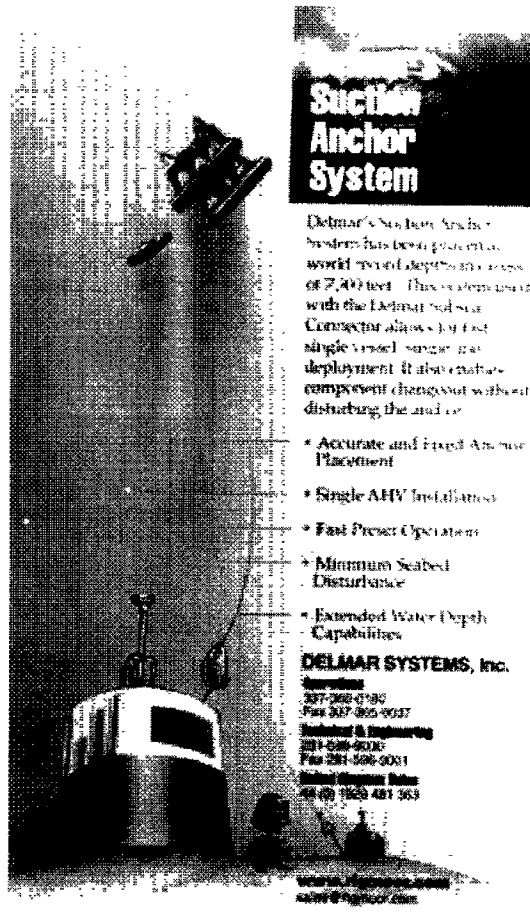
WEST has reviewed 20 deepwater rigs for aid in understanding what systems are currently in place and the operating experiences with them thus far. Assessments were conducted using an ATP (Acceptance Testing Procedure) developed specifically for each rig. These documents, when completed by WEST surveyors, offer one source of data. A second source was the WEST historical files from prior studies and visits to these rigs. A third source were the manufacturers of secondary intervention systems, operators, and drilling contractors.



Discoverer Enterprise



Sedco Express
Sisters = Cajun Express and Sedco Energy



What is the conventionally moored water depth record now?

Some have multiplex control systems.

As noted in Section 3 Terms and Definitions, systems with different characteristics can be referred to by the same name. Thus, the precise definitions noted in that section will be utilized herein.

5.1 System Details

Note: The drawings included in this section are representative only. Components that have no direct bearing on the function of the system have been deleted for clarity.

5.1.1 Deadman and AMF (Automatic Mode Function) Systems

5.1.1.1 Summary

Deadman

Application	MUX, hydraulically piloted possible
Function	sequence
Activation	automatic, loss of electrical and hydraulic signals
Commonality	independent

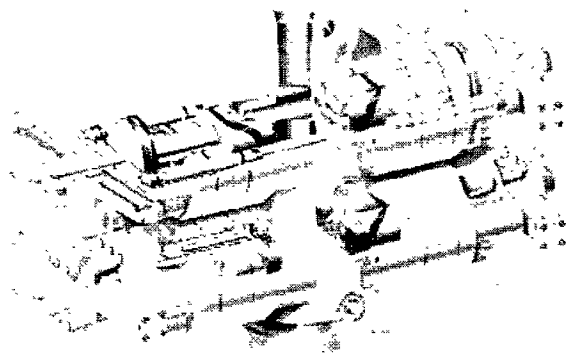
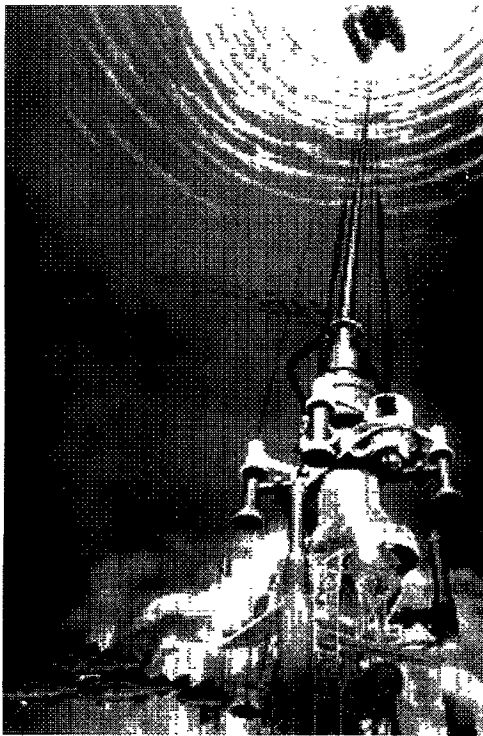
AMF

Application	MUX
Function	sequence
Activation	automatic, loss of electrical and hydraulic signals
Commonality	SEM (Subsea Electronics Module)

The Deadman system is installed on the lower BOP stack and operates independently of the pods, while the AMF system is incorporated into the pods and is dependent upon at least one pod being functional as it utilizes pod components for actuation of the system.

5.1.1.2 Overview

Deadman/AMF systems automatically shut in the wellbore without human input in response to a loss of both communication links to the surface, hydraulic and electrical, as would occur upon parting of the riser or the accidental disconnect of the riser. In order for the deadman system to initiate closing of a ram, the system must first have been armed and placed in standby mode with all circuits functional. The system remains inactive if there is hydraulic supply to either pod or if either pod has electronic communication to the surface. Upon total loss of all hydraulic pressure and communication to both pods, the system (if armed) is activated and shuts the well in through the use of hydraulic fluid stored in dedicated accumulators. Some systems operate only the blind shear rams and locks, but others also supply closing pressure to the choke and kill valves.

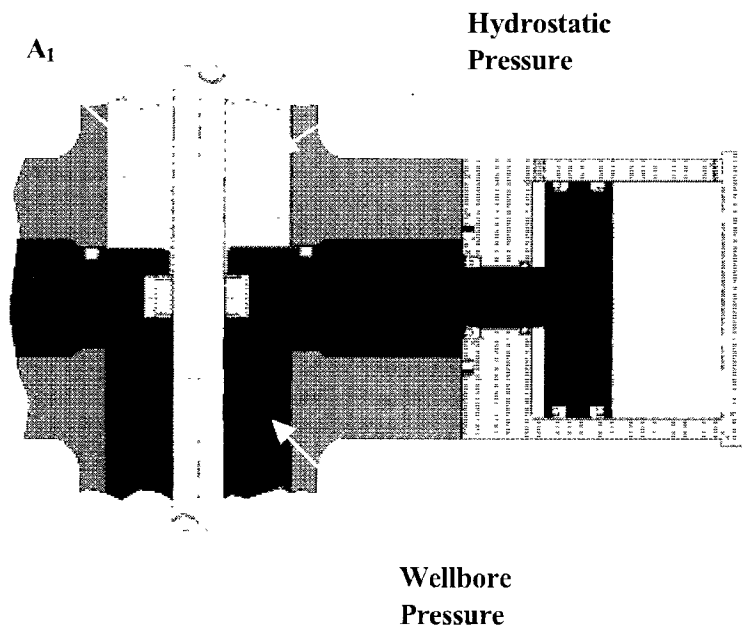


Wedgelocks on a Cameron Type U II BOP, Shear Rams and VBRs.

Why do we need ram locking systems?

Deadman/AMF systems are very good means of secondary intervention but require massive, across the board failures in order to operate. Should a total loss of hydraulic power be experienced during a blowout, for example from a ruptured conduit line, but the MUX cables remain intact, the system would not activate. Likewise, should the MUX cables part or some drill floor disaster disable the control panels, the system would not activate because hydraulic pressure would still be present. In either case, the Deadman/AMF systems would not activate even though there would be no other means to operate the pods.

Ram Unbalanced Area or Wellbore Assist Area



The area above the packers, A_1 , does not have wellbore pressure acting on it and is, therefore, “unbalanced”. This creates the wellbore assist pressure creating reliable ram sealing.

Of the systems that have been studied, some would have been ineffectual due to design limitations. Even though the systems depend on the absence of hydraulic pressure, a check valve was included in the circuit that would have prevented loss of hydraulic pressure in the pod even had the riser parted.

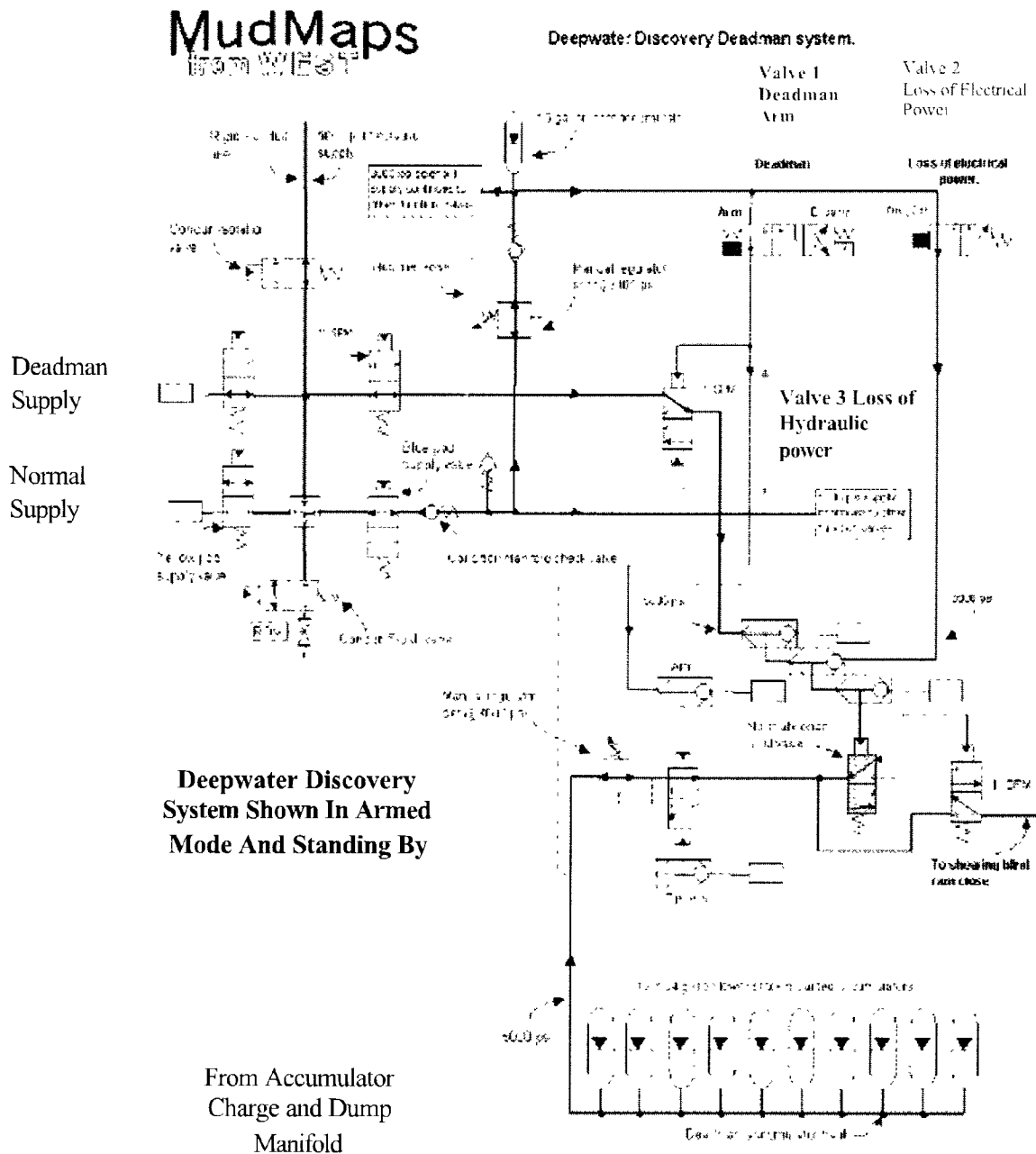
Additionally, a combination of inadequate maintenance and no risk assessment have led to systems that will inadvertently close the shear rams, at least partially, without the knowledge of the rig crew. This has led to at least one case of substantial downtime. (Drawing 1149-03)

The most serious drawback to this system, however, is the mind set of rig personnel. Many operator and contractor personnel refuse to arm the system from fear that it will either not operate when needed or activate inappropriately, causing downtime. If the system is not armed, it will not provide the design safety functions.

5.1.1.3 Typical Deadman System Description

When the system is operated to the armed position, solenoid valves pilot both the loss of hydraulic and loss of electrical power valves to the armed position. Both of these valves supply a signal, via shuttle valves, to the normally open deadman SPM valve, colored orange, which holds the deadman valve in the closed position. Should loss of electrical power occur, Valve 2 would spring shift to the vent position, but the deadman valve would still be held in the closed position by Valve 3. If hydraulic pressure in the rigid conduit hydraulic supply line on the drilling riser were also lost, supply pressure to the Valve 3 would be vented, and the deadman SPM valve would spring shift to the open position, closing the blind shear rams.

Figure 2
Deepwater Discovery Deadman System



5.1.2 EHB (Electro Hydraulic Backup) Systems

5.1.2.1 Summary

Application	MUX
Function	sequence
Activation	manual
Commonality	MUX cables, solenoid valves, other

5.1.2.2 Overview

The EH backup provides the user with the option of using hardwired, pre-selected functions in the event of lost communications. Typically, the hardwired functions available would be the same that would be found if only ROV secondary intervention were in use, i.e. one or two rams, the LMRP riser connector, etc. This system has its own backup power supply so it does not depend on primary system power. The amount of current that is sent to the solenoid valve coil can be manipulated to provide additional current in the event it is difficult to operate. This ability to manipulate current can cause unseen damage during testing if too much current is used. The system does not provide additional redundancy in the event of an accidental riser disconnect or separation.

The EH backup system requires a hard wired umbilical, and is not offered by the manufacturer on the modern fiber optics systems.

5.1.3 EDS (Emergency Disconnect System)

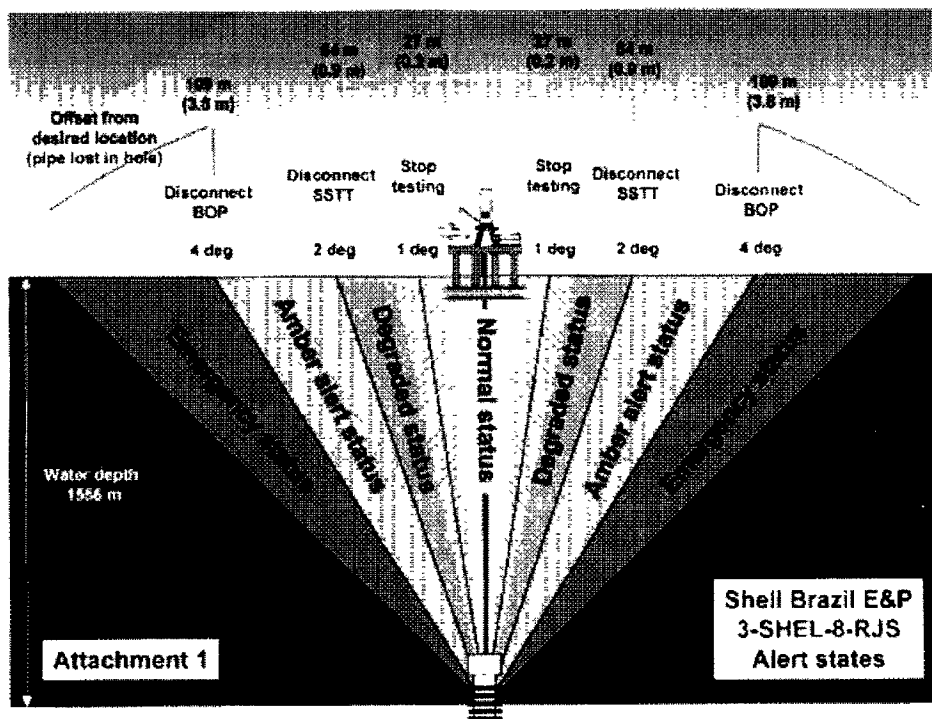
5.1.3.1 Summary

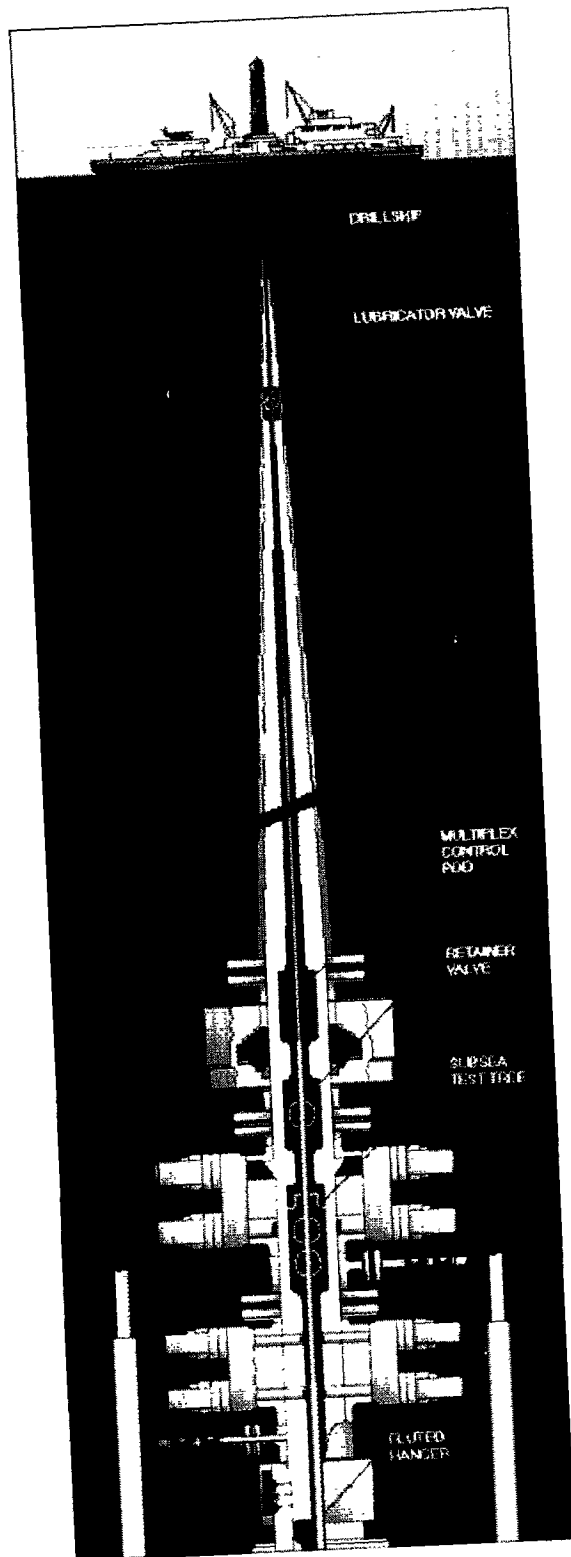
Application	MUX
Function	sequence
Activation	automatic, watch circle
Commonality	full

5.1.3.2 Overview

All dynamically positioned rigs are equipped with an emergency disconnect button which initiates a pre-programmed sequence of functions designed to secure the well in a minimum amount of time prior to disconnection of the LMRP riser connector. The amount of time required to complete the entire sequence varies from rig to rig depending on the complexity of the stack and can vary from 30 seconds to a minute or more. If a stack has dedicated shear accumulators, the time required to unlatch can be significantly reduced because the shear rams will continue to close even after the LMRP separates. One area of concern is the inability of the software of some systems to be reprogrammed on the rig.

DP Watch Circles



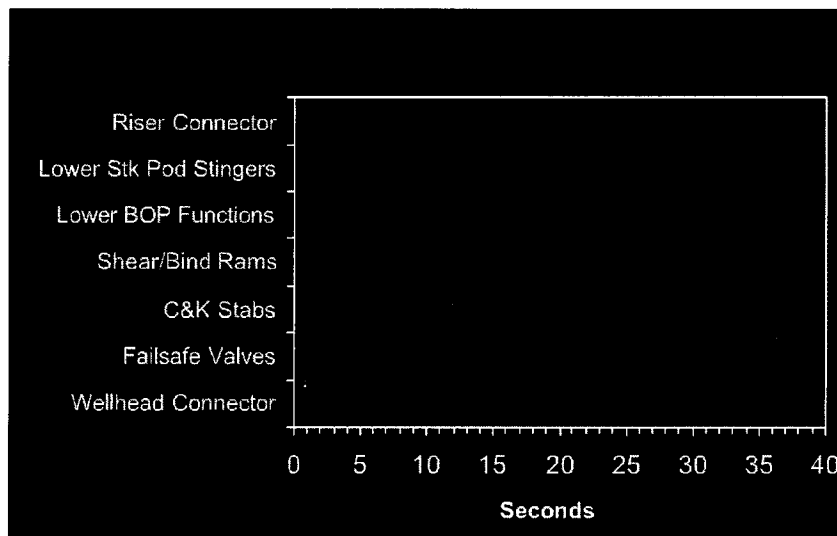


Emergency Disconnect Sequences
The main task of the DP system is
to hold the riser vertical.

5.1.3.3 Typical EDS Sequence

Although sequences vary from rig to rig, one simplified EDS sequence is shown below. It is interesting to note that some functions are activated even though they should already be in a particular position, e.g., the choke and kill valves. This is done to ensure the well is secured upon disconnect. Being controlled by a PLC allows the timing of the system to be tuned during installation. This allows the rig, if necessary, to ensure a previous function is completed before another is initiated. Additionally, multiple EDS sequences can be programmed for different drilling conditions. The most challenging application is on those rigs that have casing shear rams; one sequence might include the non-sealing casing shear in the circuit, followed by the sealing blind shear, while another eliminates the casing shear activation.

Typical EDS Timing



5.1.4 Auto Disconnect

5.1.4.1 Summary

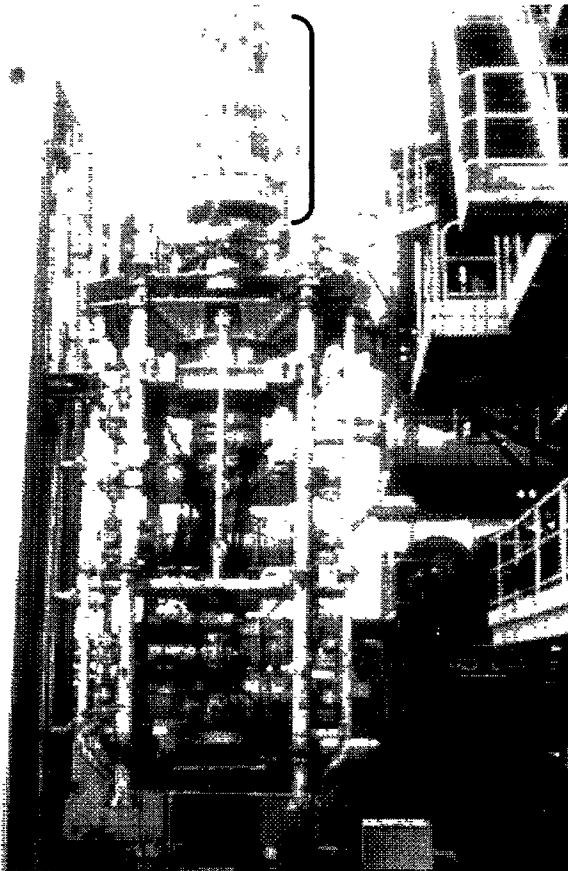
Application	hydraulically piloted, MUX possible
Function	LMRP connector
Activation	automatic, flex joint angle
Commonality	independent

5.1.4.2 Overview

This is a new system, recently installed in the Norwegian sector of the North Sea. There is insufficient field experience with this system for a meaningful discussion of its advantages or disadvantages at this time. However, it should be noted that the use of a system similar to this could have real advantages in the GoM during hurricane and loop current season when dragging anchors is a possibility that could cause failure of the wellhead.

5.1.4.3 Typical Auto Disconnect System Description

This system was designed in response to a risk analysis. The analysis determined that in the event of lost station, combined with a failure to disconnect, the weakest link was the wellhead, which would be pulled over. Auto disconnect systems utilize stand alone circuits designed for use with a hydraulically piloted control system. Their sole function is to disconnect the LMRP. It should be used in conjunction with an autoshear circuit.



Terminology

**LMRP = Lower Marine Riser
Package**

When the Flex Joint reaches a pre-set angle, the triggering mechanism activates the triggering valve (11). Hydraulic pilot fluid from the Pilot Accumulators (14) activates the following:

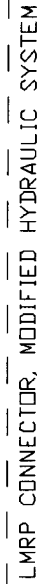
- 1) Main Emergency Unlock Valve (9). Hydraulic power fluid from the dedicated accumulators on the LMRP (16) will flow through the Triple Flow Divider (8) and operate the LMRP connector (19) to the unlock position. Note that the kill and choke line connectors that could prevent LMRP release are equipped with a mechanical backup release function and are, therefore, not unlocked hydraulically.
- 2) Backup Vent Valve (1) will allow discharge of exhaust fluid from the LMRP connector (19). This, together with what is described in Point 4 below, will provide redundancy to avoid the possibility that a single failure can prevent disconnect.
- 3) Pilot Vent Valve (4) to close the Pilot Operated Check Valves (5) to prevent back-flow through the main control system.
- 4) Pilot operated Check Valve (2) to allow exhaust flow from the LMRP connector (19) back through main control system. The Triple Flow Divider (8) will split the flow from the accumulators (16) in three equal flows to the respective set of hydraulic cylinders in the LMRP connector (19). In case of line rupture of any of the three circuits, the fluid that will exhaust to the sea will then boost pressure in the two circuits that are still intact. (15)

The predefined flex-joint angle triggering mechanism has the following features:

- Operates the trigger pilot valve if a predetermined flex-joint angle is reached for any reason and in any direction.
- The trigger mechanism converts flex-joint angular displacement to axial displacement of an actuator ring. This is achieved by use of three pair of hydraulic synchronization cylinders.

The system allows for testing at surface by use of a “go - no go” gauge.

Figure 3



N:\CONSULT\N S\J149 Secondary Intervention\Final Report\System Drawings\UNEP Connector Modified Hydraulic System.dwg

5.1.5 Autoshear Systems

5.1.5.1 Summary

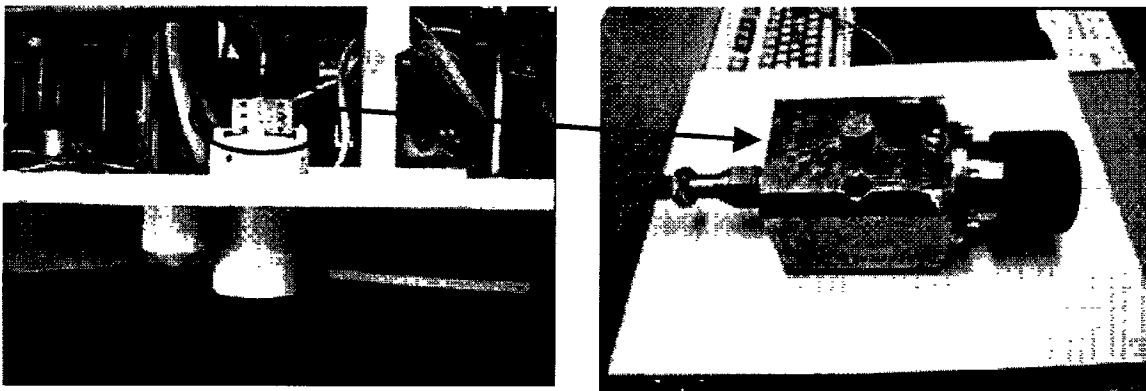
Application	MUX, hydraulically piloted
Function	shear
Activation	automatic, LMRP separation
Commonality	independent

5.1.5.2 Overview

An autoshear system is similar to deadman/AMF systems in that it automatically closes the blind shear rams, but the underlying principle of operation is different. Only the accidental or intentional disconnection of the LMRP riser connector can initiate an autoshear. If the riser parts during drilling, the system will not activate. Like deadman/AMF systems, the autoshear must be in the armed and standing by mode in order for the system to be functional. It is armed either manually on the surface prior to running the stack or by an ROV after the stack is latched to the wellhead. A spring loaded, mechanically operated valve is installed on the BOP stack between the top of the lower stack and the LMRP. When the LMRP is in place, the valve handle is maintained in the inactive position. When the LMRP is separated from the BOP stack, a spring shifts the valve to the active position and, if in the armed position, fluid is directed to the shear ram close function from dedicated accumulators on the stack.

An autoshear system suffers from some of the same drawbacks as the deadman/AMF systems. In at least one known case, the blind shear rams were activated due to deflection of the LMRP during testing of the choke and kill lines. Fear that the shear ram will be activated at the wrong time often means that the system remains in the disarmed position at all times.

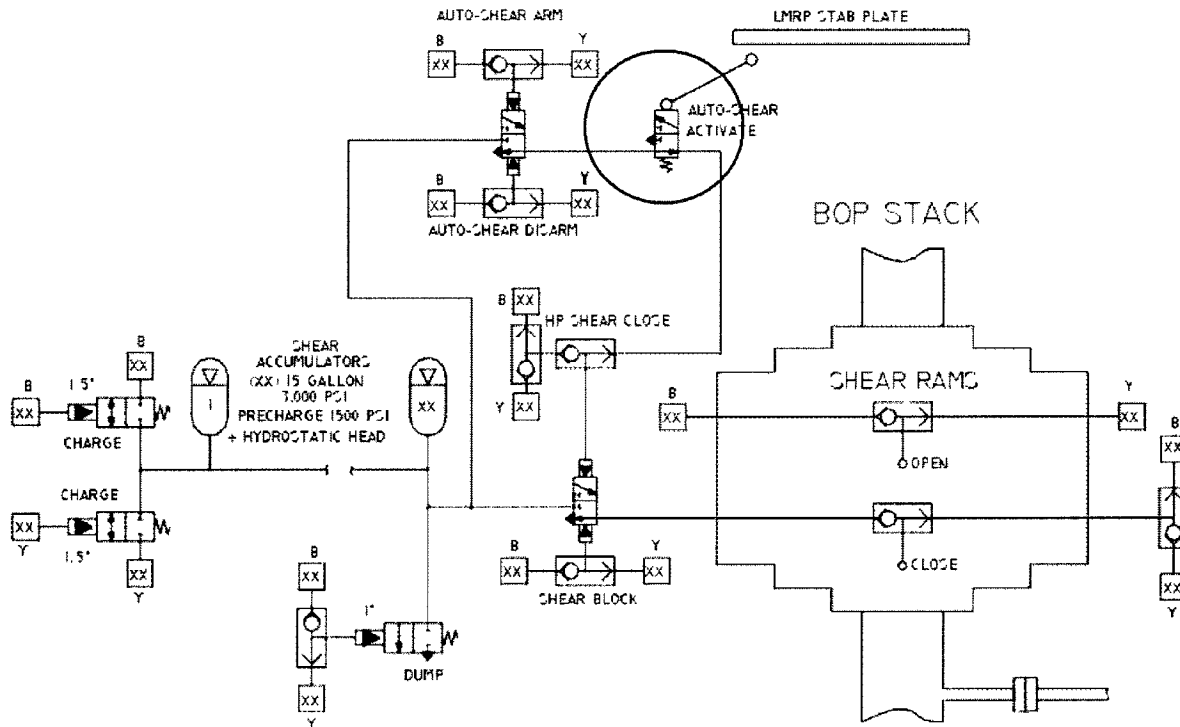
Proximity Switch on LMRP



The proximity switch on the LMRP fires the autoshear when the LMRP is lifted off the BOP stack.

5.1.5.3 Typical Autoshear System Description

Figure 4
Typical Autoshear System Description



The mechanical operator of the autoshear valve, circled in red, is held in the inactive position by contact with the LMRP stab plate. If the LMRP connector is unlatched and lifted off the stack, as shown in the sketch, a spring shifts the autoshear valve to the “shear” position, supplying high pressure operating fluid to the close chamber of the shear ram.

5.1.6 Acoustic Backup Systems

5.1.6.1 Summary

Application	MUX, hydraulically piloted
Function	discreet, several
Activation	manual
Commonality	independent

5.1.6.2 Overview

An acoustic BOP control system is intended to provide backup operation of critical BOP functions in an emergency, and is unaffected by any damage to or loss of the primary control system. Acoustic backup control systems are in use primarily in the Norwegian sector of the North Sea and offshore Brazil. Most of the newer generation acoustic systems are capable of operation in water depths greater than 10,000 feet.

5.1.6.3 Discussion

The manufacturers of acoustic BOP control systems specify water depth capability based on the assumption of “normal” noise levels. But acoustic system performance depends on a number of factors, one of which is the signal to noise ratio at the receiver. There are receivers both at the surface and on the stack. Noise generating components on the surface (such as thrusters) are dealt with during the design and commissioning of the rig. The acoustic control system manufacturers do not have noise data for blowouts and thus neither design for nor guarantee operation during a blowout. Acoustic systems are useful in situations where the primary control system has failed but may not function if the well has significant flow.

Line of sight communication is a requirement of acoustic systems. Even with widely spaced dual stack mounted transceivers, communication cannot be relied upon in the presence of mud clouds or gas plumes. There has been some experimentation with placing remote hydrophones or relay beacons on the sea floor 100 meters from the BOP stack to improve communications during a blowout; however, to date there have been no published results.

One test that has been performed as part of new rig commissioning is dumping all mud tanks into the moon pool to intentionally create a mud plume between the hydrophones and sea floor beacons. This test consistently interrupted communications with older acoustic systems (pre-1990). With some modern acoustic systems this test does not noticeably affect operation. It is not known how closely this test resembles a plume of well bore fluids at the BOP, nor has this test been performed with all modern acoustic systems.

Another weak point may arise in the method of control. Some acoustic systems assume that the primary control system is totally inoperative, but this may not be the case. If the primary control system is active when the rig is abandoned, the rams may be pressurized to the open position. If that were the case the acoustic system would not be able to close the rams. These acoustic system can be modified to override the primary system.

Operating in a wide range of water depths has caused problems in the GoM. Rigs have experienced problems moving from deepwater to the Grand Banks, where some of the areas of operation are in only a few hundred feet of water. The gain of the acoustic system was set for deeper water. The transmitted commands would reverberate between the surface and seafloor - a condition known as "multipath". The BOP-mounted receivers could not decode the commands and thus did not function in the shallow water. System gains had to be reduced to eliminate the multipath effect. Similarly, problems arise if a rig set up for shallow water moves to significantly deeper water. In this case a signal that worked in shallow water may be too weak to reach the BOP in deep water. Depending on system design, changing transmit gain may require system modification by the manufacturer.

Significant doubts remain in regard to the ability of an acoustic control system to provide a reliable emergency back up to the primary control system during an actual well flowing incident. Environmental factors that would be expected to exist during an emergency, such as high noise and/or a mud cloud, may prevent reliable actuation of stack functions with acoustics. Acoustic controls manufacturers are aware of the issue and argue that modern acoustic systems either already will, or can be modified to function during a blowout. However, to date they have no actual test data or model of blowout noise that can be used for evaluation or implementation of an appropriate design. Modern acoustic controls are based upon military systems that allow reliable underwater communications over more than 20 kilometers. There is a dearth of data about acoustic BOP control operation. WEST does not know of an incident where an acoustic system has been used to operate the BOP during a blowout, either successfully or unsuccessfully.

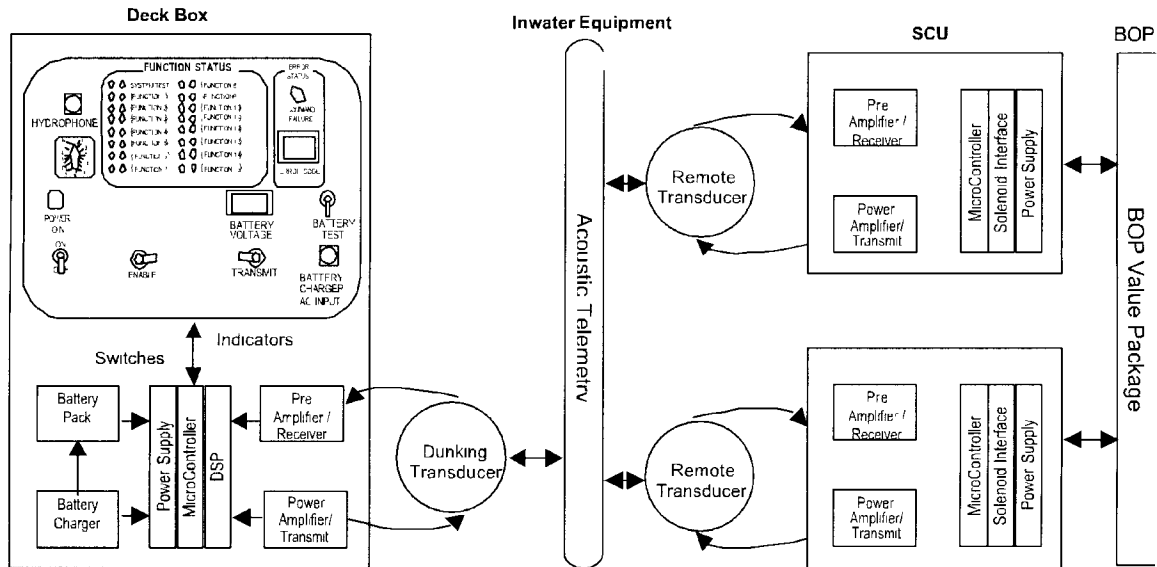
In spite of the above it should be noted that some operators have elected to use acoustic control systems as the primary system with no backup other than ROV intervention. These are used on wells drilled from a floating platform but using a surface BOP stack for well control. The acoustic system controls a single blind/shear ram and two hydraulic connectors on the sea floor. This system is known as either the Seafloor Isolation System or the Environmental Safeguard System. Regardless of the name, the system is not considered a component of well control and is, therefore, not subjected to the same requirements and regulations.

It is clear that there is room for more study of acoustic control performance during a blowout. Further study could be focused on acquiring and analyzing data for the purpose of better understanding the capabilities on acoustic performance during a blowout. This study should be conducted in conjunction with industry experts.

5.1.6.4 Typical Acoustic System Description

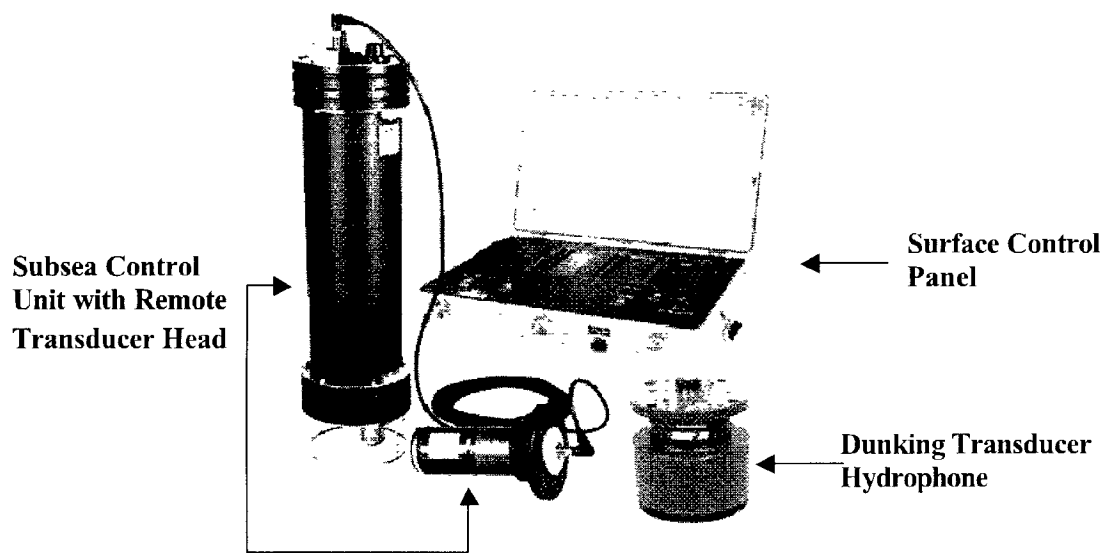
If evacuation of a drilling rig becomes necessary before an emergency disconnect can be achieved, an acoustic pod can be provided to accomplish a disconnect. The system consists of the surface control unit and receivers communicating with a pod mounted on the lower stack.

Figure 5
Typical Acoustic System



The surface unit consists of a portable control console, cable drum with cable, and a dunking transducer. The sub sea unit consists of a battery, control electronics, and two (redundant) transducers. Surface generated commands for the acoustic pod are received and processed in the subsurface electronics.

Figure 6
Acoustic Components



The subsea unit converts surface generated commands into voltages for actuating electro hydraulic valves in the acoustic pod. Each acoustic pod function is activated by a unique command from the surface. Subsea transducers convert each command into an electrical signal, and the electronics package produces a voltage that energizes the appropriate solenoid assembly. The energized solenoid applies hydraulic pilot fluid to the associated SPM valve. As a result, the SPM valve opens and applies fluid to the appropriate BOP function.

Typically, the following commands can be issued from the surface unit:

- Arm - applies hydraulic pressure to the various function SPM valves in the pod.
- Disarm and Reset - removes hydraulic pressure from the SPM valves of the functions.
- Lower Riser Connector Unlatch - orders the BOP to unlatch the lower riser connector.
- All Stabs Retract - orders the BOP to retract all stabs.
- Blind/Shear Rams Close - orders the BOP to close the shear rams.
- Middle Pipe Rams Close - orders the BOP to close the middle pipe rams.
- Lower Pipe Rams Close - orders the BOP to close the lower pipe rams.
- Casing Shear Rams Close - orders the casing shear ram closed

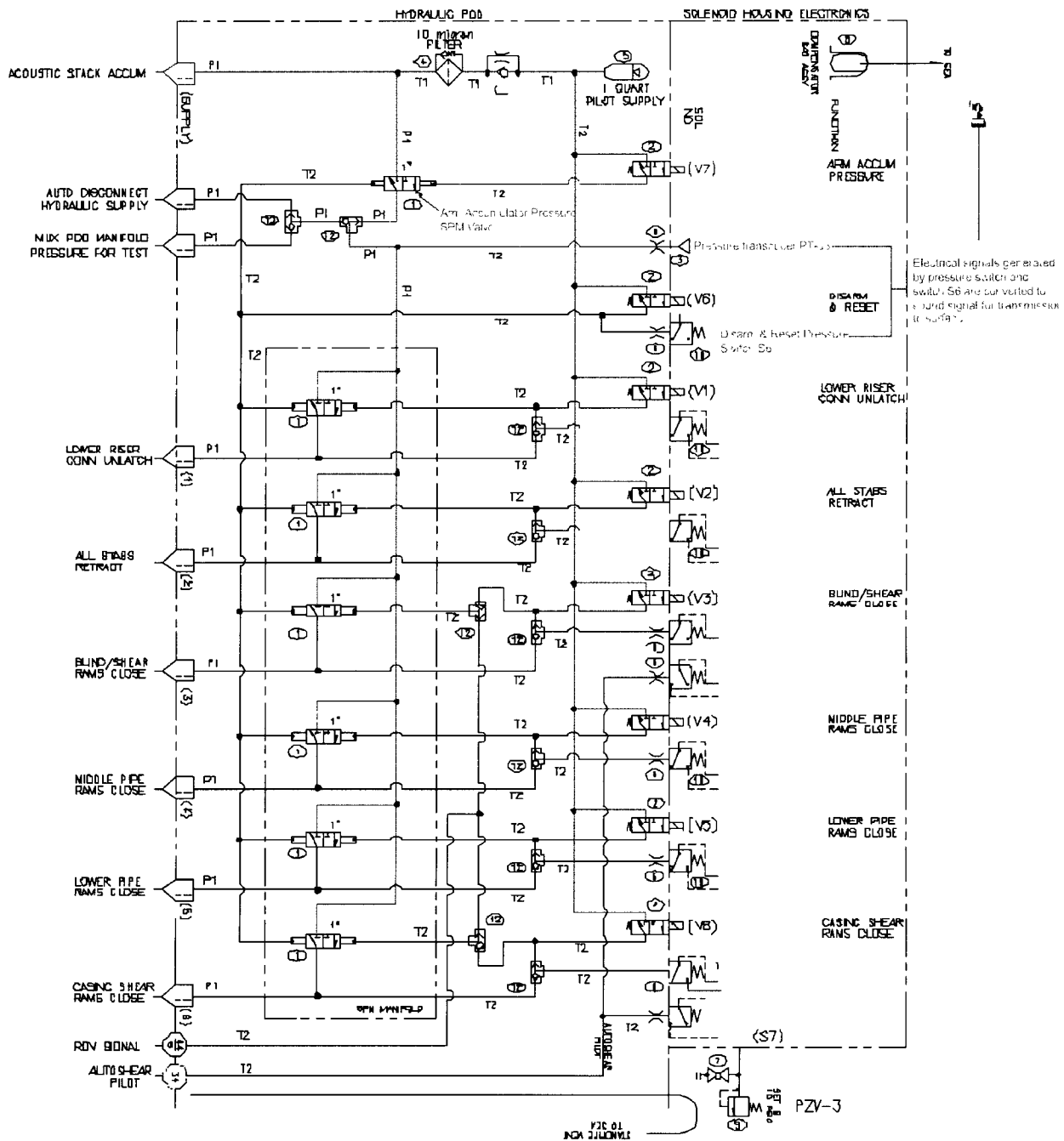
The pilot fluid is also applied to a pressure switch changing the state of the switch. The resulting change in state is processed and transmitted as a sound signal to update the surface control unit.

5.1.6.5 Example Function Actuation

Arm command

When the arm command is transmitted (refer to Figure 1), the transducer converts the arming command into an electrical signal for the subsea electronics package. The package responds by applying a voltage to the solenoid (V7). The solenoid opens and applies pilot fluid to the Arm Accumulator Pressure SPM Valve. This SPM valve opens and applies hydraulic fluid to the supply ports on SPM valves 1 through 6, Pressure Transducer (PT-33), and Disarms and Reset the Pressure Switch (S6). Electrical signals representing the pressure change registered by the PT and the closure of switch S6 are converted to sound signals for transmission to the surface. These signals update the surface control unit.

Figure 7
Subsea Acoustic Control Pod



5.1.7 ROV Intervention

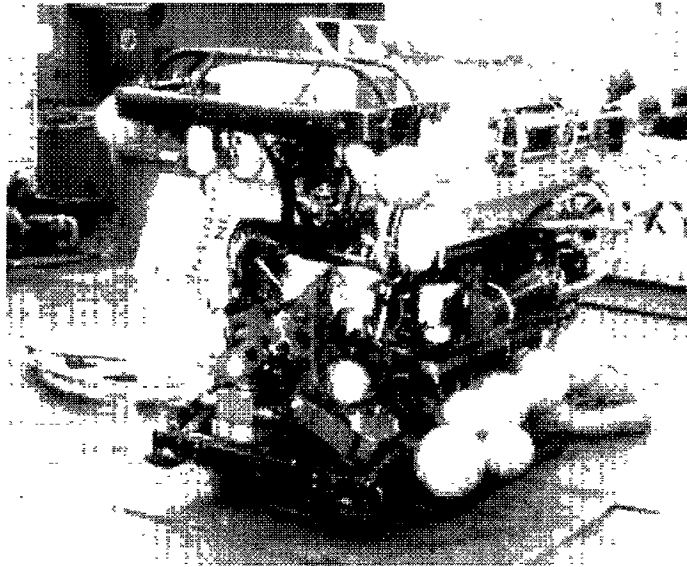
5.1.7.1 Summary

Application	MUX
Function	discreet, several
Activation	manual
Commonality	independent

5.1.7.2 Overview

ROVs are the simplest and most effective means of secondary intervention in use today. One reason they are effective is that they are not automatic systems, but require a human action in order to operate, which makes them more trusted by the rig crew. This is true in spite of the fact that design and plumbing errors can cause malfunctions of the primary control system.

Capabilities of ROVs



After docking, an ROV has the capability to push, *pull* and rotate with a manipulator arm, but at only 4.5 gpm (average) – 6.7 minutes is needed to close shear rams requiring 30 gallons.

Unfortunately, if an ROV is needed for well control, there is a good chance that it will be incapable of closing a ram for one or more reasons. As a result, reliance on ROV systems as the sole means of securing the well if the primary system has failed has a high probability of failure unless the ROV is docked at the appropriate ROV panel the during drilling.

Weather is often a factor in the ability to launch an ROV; if it can't get in the water, it can't do its job. Even if the weather cooperates and the ROV can get in the water, subsurface conditions might make it impossible to reach the stack. High currents prevent ROV operations, and they are virtually useless during loop currents, which can shut them down for weeks at a time. Even if the weather and water conditions were perfect, if turbulence from an uncontrolled well flow is present, the ROV would probably be unable to fly in close enough to the stack to successfully shut in the well.

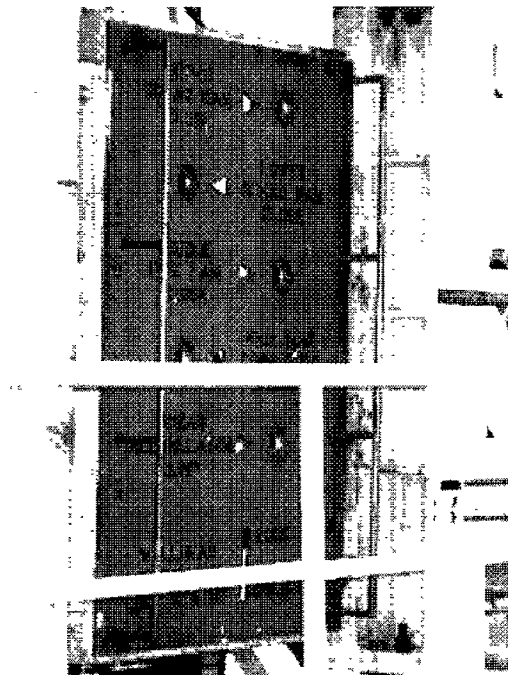
Another weak area is the low pumping rate supplied by the ROV hydraulic pump. The pump rate ranges from about 1.5 to 9.0 gpm (gallons per minute), with the lower number most often found. A Cameron 18 3/4" 15,000 psi WP ram BOP requires 24.6 gallons to close fully. At 1.5 gpm, the time required to close the ram is over 16 minutes. Even at a mid range output of 4.5 gpm, over five minutes would be needed. While the sealing mechanism and cutting blades are more robust in some preventers than in others, it is considered highly unlikely that any preventer currently available would stand up to this punishment during an uncontrolled flow of wellbore fluid. However, no tests have been conducted to verify this.

There are currently no requirements to function test ROV circuits prior to running the stack, and this is often overlooked. In addition, there is no standardization concerning the stab connections, with each ROV company supplying their own equipment. Unless they are specifically requested to do so, the female stab receptacles on the stack are not replaced when the ROV comes on board, which results in incompatible equipment. A single design ROV stab should be adopted for use throughout the GoM, and all ROV operable circuits should be function tested prior to running the stack. Ram BOPs with ROV intervention capability should be wellbore pressure tested prior to running the stack after closing, locking and venting the ram with the ROV circuit. This would not require the use of the ROV, but could be done with a hydraulic pump using BOP control fluid.

The IADC recommends the following as minimum requirements for ROV intervention for the purpose of well control.

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

Figure 8
Typical ROV Panel



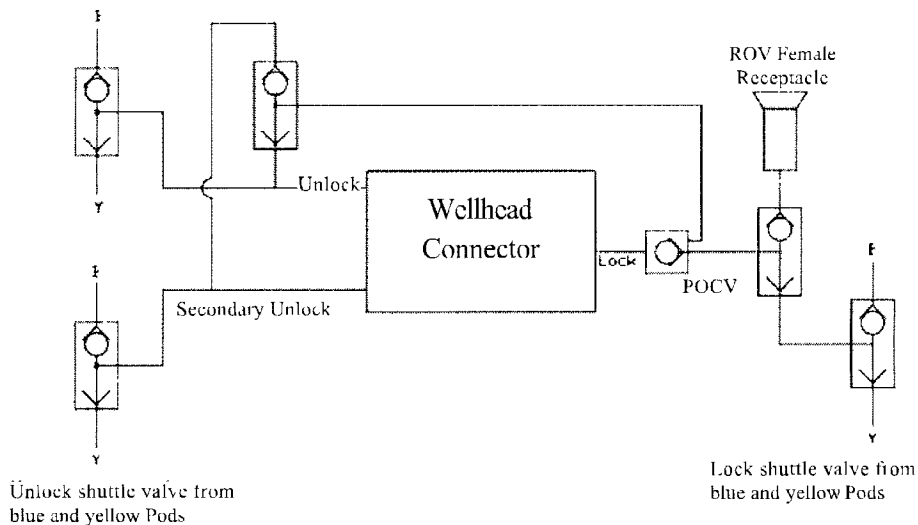
5.1.7.3 Example ROV Secondary Intervention Circuits

Wellhead Connector

When the LMRP is disconnected from the BOP stack all pressure is vented. Due to the possibility of backdriving (the opening of the wellhead connector) in the presence of wellbore pressure, it is desirable to maintain pressure on the lock chamber. This can be easily accomplished with a ROV.

The following circuit is typical of the ROV secondary intervention found on most rigs regardless of water depth. The purpose is to allow the ROV to apply latch pressure to the wellhead connector, ensuring that the connector preload is maintained after the LMRP is disconnected or the control system becomes inoperable for an extended period. The Pilot Operated Check Valve (POCV) traps pressure on the lock chamber of the connector, helping to maintain preload. The ROV can replenish the pressure at intervals should the POCV leak.

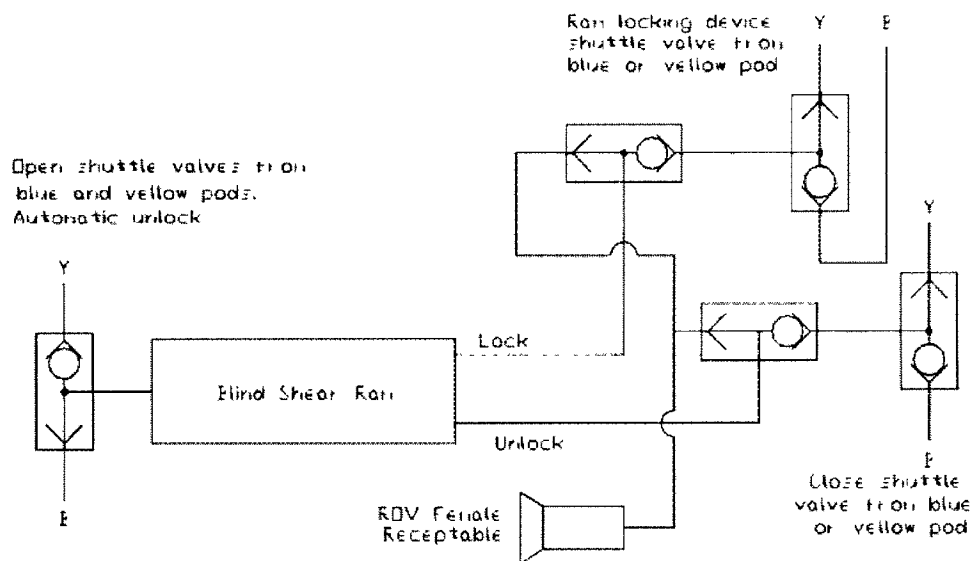
Figure 9
Example ROV Secondary Intervention Circuits



Blind Shear Ram

If well control operations were required from the ROV, a likely function for activation is the shear ram. The circuit below is typical of the shear ram ROV secondary intervention circuit found on most rigs regardless of water depth. The purpose is to allow the ROV to apply close pressure to the blind/shear ram while simultaneously locking the ram. Note that the locks on some rams may require the ROV to supply fluid through two separate ports. The ROV will be able to help secure the well, assuming the well is not flowing. If flowing, the ROV may not be able to close the rams due to the turbulence it will encounter.

Figure 10
Shear Ram ROV Circuit



If additional ram type BOPs are ROV operable, they would be connected in a manner similar to the one shown above.

5.2 Secondary Intervention Systems by Rig

Table 2
Secondary Intervention Systems by Rig

Rig Name	GoM	Type	Water Depth	Control System	ROV	EDS	Deadman	AMF	Acoustics	EH Backup	Autoshear
Rig 1	No	Moored	1500	Shaffer Koomcy w/ 42 Line Pod	Yes	No	No	No	Yes	No	No
Rig 2	Yes	DP	7000	Shaffer/Tri-Tech MUX	Yes	Yes	No	No	No	No	Yes
Rig 3	Yes	DP	10000	HydriL MUX	Yes	Yes	Yes	No	No	No	No
Rig 4	Yes	DP	10000	Cameron MUX	Yes	Yes	No	Yes	No	No	No
Rig 5	Yes	DP	10000	HydriL MUX	Yes	Yes	Yes	No	No	No	No
Rig 6	No	DP	10000	Cameron MUX	Yes	Yes	No	Yes	No	No	No
Rig 7	No	DP	8000	Cameron MUX	Yes	Yes	No	Yes	No	No	No
Rig 8	No	DP	8200	Cameron MUX	Yes	Yes	No	Yes	No	No	No
Rig 9	Yes	DP	7500	Varco Shaffer MUX	Yes	Yes	No	No	No	No	No
Rig 10	No	DP	6000	Cameron MUX	Yes	Yes	No	Yes	No	No	Yes
Rig 11	No	DP	6000	Cameron MUX	Yes	Yes	No	Yes	No	No	Yes
Rig 12	No	DP	7500	Cameron MUX	Yes	Yes	No	Yes	No	No	No
Rig 13	No	DP	8200	HydriL Trittech MUX	Yes	Yes	Yes	No	Yes	No	No
Rig 14	Yes	DP	10000	ABB Seatec MUX	Yes	Yes	Yes, disabled	No	No	No	No
Rig 15	Yes	Moored	2200	Cameron Payne Hydraulic	Yes	No	No	No	No	No	No
Rig 16	Yes	Moored	6000	Shaffer MUX	Yes	No	No	No	No	No	No
Rig 17	No	Moored	1500	Shaffer Koomcy Hydraulic	Yes	No	No	No	No	No	No
Rig 18	No	DP	7500	Cameron MUX	Yes	Yes	No	Yes	No	No	No
Rig 19	Yes	Moored	5000	Shaffer Koomcy Hydraulic	Yes	No	No	No	No	No	No
Rig 20	No	DP	6000	Cameron MUX	Yes	Yes	No	Yes	No	No	No

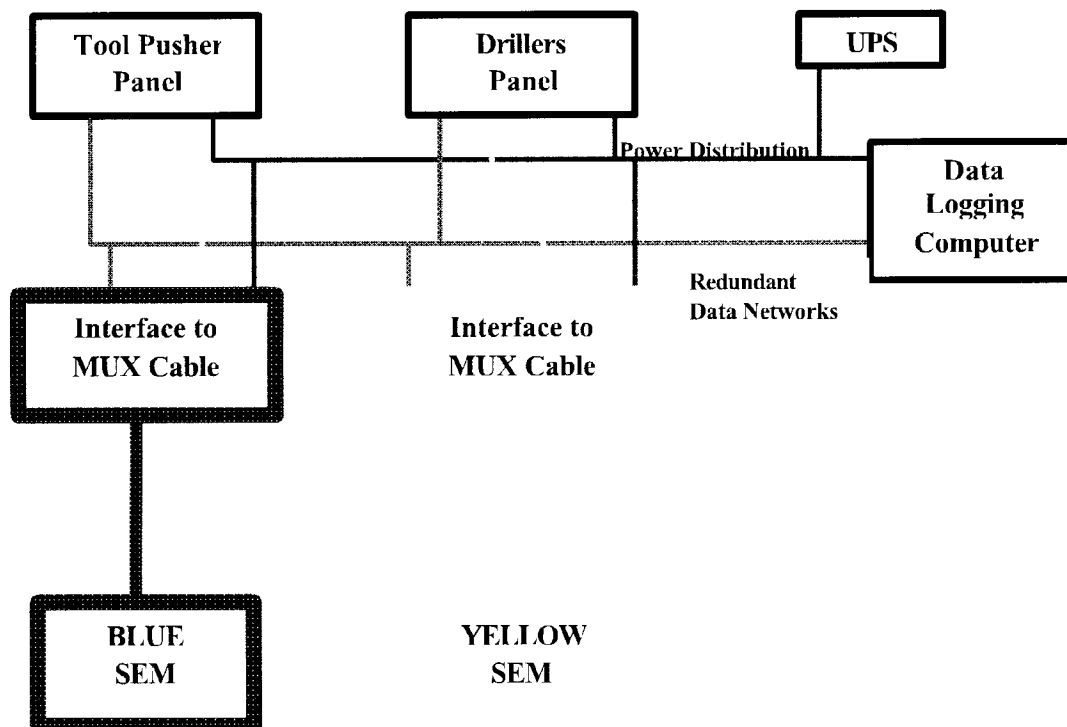
6 Identify best practices in use and how they can be improved

6.1 Critical Issues

The attached Matrix of Issues serves as a tool to understand how the various systems address critical issues. Critical issues are as follows:

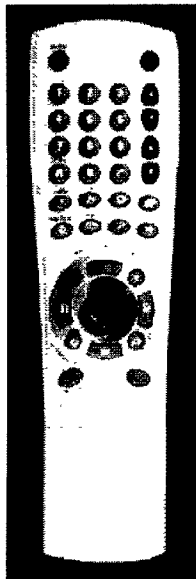
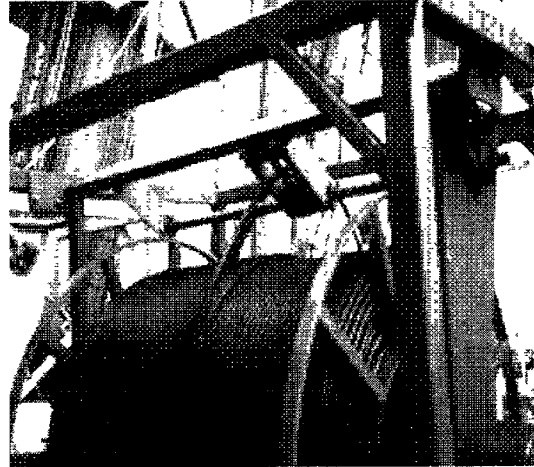
- Fast response – Response time in this section is defined as the amount of time required for a particular system to be deployed from the time the need for system deployment is realized. Well control using secondary intervention is most likely to occur due to either an unplanned disconnect of the LMRP connector or separation of the drilling riser. Either scenario results in the loss of hydrostatic head in the riser if drilling, which can cause the well to begin flowing. When the flow of formation fluids begins, it often starts slowly but increases in volume rapidly, thus there is a relatively narrow window of time available in which to regain control of the well. Failure to address the beginning of a kick will result in ever more violent flows. A secondary intervention system that will be relied upon to shut in a flowing well must be in place and ready to function immediately if needed.

Basic MUX System Components



MUX Reel with Level Winder

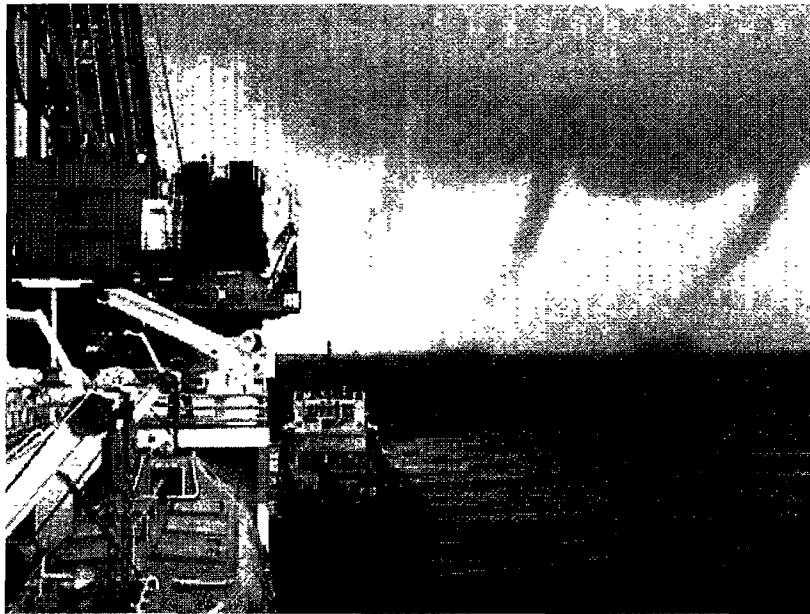
- Level winder mechanically synchronized to drum and cable size
- Diameter of new cable
- Fleet angle can be large
- MTBF of slip rings is critical, also spares
- Leave space for expansion
- Location of controls



Multiplex Control Systems Everyone Will Recognize

- Sufficient capability – Capability in this section is defined as the speed at which the well control event occurs after the system has been deployed. Some secondary intervention systems in use today have limited capability and require excessive amounts of time to close a ram BOP. These systems may not have the capability to secure the well under high flow conditions. It is strongly recommended that no secondary intervention system be relied upon to secure a flowing well unless it can fully close a ram BOP in the API prescribed time of 45 seconds. Reference API Spec 16D, Section 2.2.2.1 and API RP 53, Section 13.3.5.
- Independence from primary system - Some emergency intervention systems are totally self contained and do not require any part of the primary control system to be functional. If, for example, the secondary intervention system relied on the MUX cables to be intact the system would become inoperative if the drilling riser parted. Stand alone systems are completely independent of the primary control system and offer an independent level of redundancy.
- Works well in adverse environmental conditions. Should a fast moving storm advance toward the rig while the primary well control system was compromised, would the secondary intervention system be able to control the well or would it be compromised?

What Would You Do?



Matrix of Issues – Secondary Intervention

Question: Will the system in place successfully address the issue delineated?

Fast Response = Can the system be deployed in sufficient time to ensure the function is completed before high flow rates damage well control equipment.

Capability = Does the speed at which the function occurs comply with API Spec 16D, Section 2.2.2.1 and API RP 53, Section 13.3.5.?

Issue	Deadman	AMF	EDS	Auto		Autoshear	Acoustic	EHB	U	Intervention
				Disconnect	Yes					
Fast Response	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	No
Sufficient Capability	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	No
Is this a stand alone system?	Yes	No, uses SEM and pod valves	No, uses MUX system	Yes	Yes	Yes	Yes	No, uses MUX cables	Yes	Yes
Works well in adverse environmental conditions?	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	No
Automatically initiated if riser & cables parted?	Yes	Yes	No	No	No	No	No	No	No	No
Automatically initiated by loss of surface electrical control system combined with loss of hydraulic supply	Yes	Yes	No	No	No	No	No	No	No	No
Works in presence of mud plume or noise	Yes	Yes	Yes	No, must be combined with Autoshear	Yes	Yes	Maybe, system dependent	Yes	Yes	Yes
Capable of containing well if LMRP accidentally disconnected, well kicks (hydrostatic head lost)	Yes	No	No	No, must be combined with Autoshear	Yes	Yes	Yes	No	Maybe, dependent on well flow rate	Yes
Capable of manually securing non flowing well	No	No	Yes	No	No	No	Yes	Yes	Yes	Yes

Assumptions: A1) ROV is deployed, not equipped with intervention stab. A2) ROV output = 4.5 gpm (7 min). A3) Secondary intervention systems are armed. A4) Acoustic system transducers deployed. A5) Accumulator volumes are adequate

- Loss of surface electrical control system. This situation would occur if the MUX cables were parted, but would also occur should the surface computer fail. This has happened in the past from such unexpected reasons as loss of GPS signal, which resulted in the shut down of the entire BOP control system, including both pods. A loss of surface electrical power would not typically cause loss of communication due to backup batteries.
- Loss of hydraulic pressure. Total loss of hydraulic power without loss of MUX communication is extremely rare, but has happened. In this case well control would not be possible unless an independent, dedicated supply of hydraulic power were available at the stack.
- Works in the presence of mud plume or noise. Should wellbore containment be compromised after the LRMP is disconnected, a large flow of drilling mud and associated debris would flow around the BOP stack. The concern is whether the secondary intervention methodology would function well in this condition.
- Capable of containing well if LRMP is accidentally disconnected. When the LRMP has been disconnected, there are no circumstances when the well should not be secured via the shear rams.
- Capable of manually securing non flowing well. Without hydraulic or electronic communication to the BOP stack, will the secondary intervention system secure a non flowing well? This is the issue

Shear Ram Blocks



Ram preventers are not designed to close and seal under high rate conditions if closure rates are slow. API Specification 16A does not require testing for rams under dynamic flowing conditions.

6.2 General

Decisions must be made regarding the level of security desired. There are many systems available that will increase the security of a BOP system, similar to the way a belt adds security to suspenders. This approach has the potential to create more problems than it solves if not thoroughly thought out in advance, and the added complexity has proven problematic in some cases.

An example would be the potential for an accidental disconnect of the LMRP connector. Current MMS regulations state that the LMRP connector function must be covered to prevent accidental unlatch, and goes on to say that the cover must be secured by a second means so that it will be different from the cover over the blind shear rams. It would be a fairly simple matter to add an interlock to prevent disconnection of the LMRP unless the shear rams were closed and locked—a reasonable practice, but added complexity.

Unfortunately, there are several instances on record of the LMRP connector unlatching accidentally due to piping errors, and other examples of an accidental unlatch without human intervention due to causes such as back pressure. In that case it would seem that an autoshear circuit with dedicated subsea accumulators would be desirable to immediately close in the well. As a last line of defense we could add ROV or acoustic system intervention, or both, in case all else fails.

The problem with the “belt and suspenders” method of safety is that it adds complexity to an already complicated system. The more systems have to interact with each other, the higher the risk of unintentional operation or failure to operate when needed. If two or more systems interact to operate the same function independently of each other, a risk analysis should be conducted and perceived risks mitigated. All leak paths must be explored to verify that a leak in one system will not have an adverse effect on the other system. In addition, no modifications should be allowed unless a full engineering review is performed to assess the potential for “designed in” failure modes.

Virtually all of the systems discussed herein will be more dependable if the system design and functionality is confirmed through a well thought out verification and testing program. In an effort to understand where the various secondary intervention systems could be enhanced, potential shortcomings have been delineated for each system. By defining the potential shortcomings, coupled with collating the above-mentioned matrix of issues, risk-reducing techniques can be more completely determined.

6.3 Deadman System

The deadman system is probably the most flexible system for deepwater rigs. If the riser has parted it usually means that both MUX control pods are inoperable and all electrical and hydraulic communication with the surface has been lost. In that scenario this system will function to secure the well. This system also fulfills the role of an autoshear by initiating the shear function if the LMRP is accidentally disconnected. The deadman system is sufficiently fast acting to secure the well before environmental or safety issues can occur in the event of riser failure or accidental disconnect.

Possible shortcomings of this system include the following:

1. Procedure implementation and training are critical to the correct and safe operation of the system.
2. System is dependent on the shear rams being capable of shearing the pipe. The subsea accumulator volume and power must be such that the pipe will shear and the shear rams seal to contain the well.
3. The system is dependent on the drill pipe tool joint being in the right place, which is simply a matter of chance. If the shear rams close on the tool joint the possibility of a successful shear are remote.
4. The ability to shear tool joints or casing would be dependent upon the stack having casing shear rams (also called super shear rams). There are no currently designed casing shear rams capable of sealing the wellbore.
5. The system is dependent on having the correct installation and maintenance. On one occasion a fault in the deadman system resulted in partial closure of the shear ram, of which the rig crew was not even aware. This failure resulted in massive damage to the BOP stack. On another occasion an incorrectly placed check valve in the subsea hydraulic circuitry would have prevented activation of the deadman system even if the entire riser was lost.
6. The system may be disarmed. If disarmed the system is totally disabled and cannot be re-armed once communication with the BOP stack has been lost.
7. ROV capability as an emergency measure should include the ability to utilize subsea accumulators as a supply source.
8. System diagnostics are essentially nonexistent. Deadman systems operate open-loop. There are no means to verify functionality of the deadman system. If the sensors, batteries, or electronics fail, the only (and first) indication of unavailability is failure to operate when needed.

The systems in operation could be improved as follows:

1. Procedures must be in place to ensure that the drill pipe would shear.
 - a. Procedures should be in place to reduce the likelihood of the shear ram blades contacting the drillpipe tool joint.
 - b. Sufficient accumulator pressure and volume to shear the drillpipe should be verified. Methodologies to test the system should be established that take into consideration water depth and mud weight.
2. Casing shear rams could be required if the rig is running casing and experienced a well control event requiring secondary intervention. However there comes a point of diminishing returns. A system utilizing casing shear rams would be complicated by the need to add sequences to ensure the casing shear rams closed before the blind shear rams. Much more useable accumulator volume would be required to close two rams instead of one. In addition, many drilling contractors at this time place the casing shear rams below the blind shear rams; their plan is to lift the casing up and then secure the well with the blind shear rams. Assuming the riser has parted a deadman sequence could result in casing shear ram closure with an inability to close the blind shear rams due to interference with the cut section of pipe. For these reasons, most systems accept the risk associated with excluding secondary intervention from addressing casing shear.
3. The design should be confirmed as sound. Change control should be in place to avoid spurious ad hoc design changes. Well thought out testing methodologies could confirm functionality and design.
4. Disarming the system for fear of accidental firing should be addressed in rig procedures. An alternate consideration may be to add an acoustic or ROV operated switch to fire the system. The risk with an acoustically operated switch would be that communications might be degraded due to subsea noise or a gas/mud plume if done after the well is flowing. Care must be exercised in acoustic system selection.
5. The design should include diagnostics. Some indication should be provided of the condition of the electronics, sensors, and batteries. This could be as simple as an LED on the subsea electronics housing (visible to the ROV) that flashes if all is well.

6.4 AMF System

This system is very similar to the deadman system described above. The AMF system uses a circuitry housed in the existing SEM unit and some of the same hardware utilized by the primary control system; thus, it is dependent on at least one pod being functional. Comments made concerning the deadman system also apply with the following exception: Unless equipped with an operable auto shear in addition to the AMF system the shear function is *not* initiated if the LMRP is accidentally disconnected. The AMF system alone will not fill the role of autoshear. All of the above issues discussed for the deadman system are relevant to the AMF system. Rigs having an AMF system are (in addition to the above problems with the deadman system) accepting the low risk that both pods might be damaged beyond use at the same time.

Means to reduce the risk of existing AMF systems are

1. The AMF system could be improved by addressing the five items above included for the deadman system.
2. If protection against an accidental disconnect is required, an autoshear feature must be added.
3. Although it is hard to visualize a set of circumstances that would destroy both pods, an in depth risk assessment should be performed on the potential for damage to individual systems.

6.5 Emergency Disconnect System

An EDS secures the well and disconnects the drilling riser in the event of a drive or drift off. It is manually initiated but performs the various functions of a safe disconnect in an automatic sequence. Most EDS systems can complete the disconnect sequence in one minute.

Possible shortcomings of this system include the following:

1. If MUX cables were non functional, it would not be possible to affect an EDS.
2. If both pods were damaged, it would not be possible to affect an EDS.
3. If an EDS is not initiated, the LMRP connector will not unlatch when required and the wellhead could be pulled over, resulting in a catastrophic loss of containment.
4. There is a chance that shearing will be on a tool joint, which will not shear unless casing shear rams are included in the sequence.

Means to reduce the risk of existing Emergency Disconnect systems:

1. The EDS sequence should be flexible enough to allow for different drilling activities. Some systems already incorporate such flexibility, for example the choice of whether to include the casing shear ram in the sequence.
2. The EDS watch circle should take into consideration the strength of the wellhead, casing, and formation supporting the casing at the sea floor.
3. If both pods are damaged, another means of secondary intervention such as auto disconnect and auto shear would be required.
4. Incorporate operating procedures to avoid striking a tool joint.

6.6 Auto Disconnect

The auto disconnect automatically unlatches the LMRP when riser angle reaches a predetermined point.

Possible shortcomings of this system include the following:

1. This system alone does not secure the well; it only provides an emergency disconnect.
2. The mechanically operated valve used to unlatch the LMRP connector must be correctly adjusted to prevent premature unlatch.
3. Like the deadman system, the auto disconnect must be armed in order to operate, except that in this case it is armed by the ROV. However, an armed auto disconnect may be more palatable to rig crews as it is mechanically activated and doesn't depend on a MUX system.

Means to reduce the risk of existing Auto Disconnect systems:

1. If combined with an autoshear circuit should be an effective means of automatically disconnecting the riser and securing the well due to a drive or drift off.
2. Include procedures to ensure that the LMRP connector is correctly adjusted to prevent premature unlatch.
3. Include procedures that address the arming/disarming of the system.

6.7 Autoshear

The issues discussed above for the deadman system are also relevant to the autoshear system. Additional shortcomings of this system include the following:

1. The autoshear secures the well only in the event of an accidental or intentional disconnect of the LMRP. If the riser is parted the autoshear is not activated.
2. The mechanically operated valve used to initiate function of the shear ram must be correctly adjusted to prevent premature shearing of the pipe. WEST is aware of at least one instance where the autoshear was initiated due to deflection of the LMRP stab plate during pressure testing of the choke and kill lines.
3. Like the deadman system, the autoshear must be armed in order to operate.
4. There is a chance that shearing will be on a tool joint, which will not shear unless casing shear rams are included in the sequence.
5. ROV capability as an emergency measure should include the ability to utilize subsea accumulators as a supply source.

Means to reduce the risk of existing autoshear systems:

1. Perform an in depth risk assessment.
2. Verify that deflection of the LMRP/BOP plates during pressure testing is insufficient to activate the autoshear. A safety factor should be included.

6.8 Acoustic Systems

An acoustic backup control system can be implemented as a stand alone system with dedicated accumulators or if the rig has a MUX system, it can utilize existing MUX solenoids and accumulators. Acoustic signals are transmitted through the water to operate specified stack functions. Possible shortcomings of this system include the following:

1. Some systems may not have hydrophones strong enough to penetrate a mud plume that would be present in a disconnect situation.
2. The correct hydrophone must be specified for deep water.
3. Acoustic interference caused by the noise of a flowing well may make operation unreliable.
4. Depending on the system, control valves may be too small to operate the ram BOP in the API recommended time.
5. Hydrophones must be in the water in order to operate. There has been at least one failure attributed to the hydrophone not being deployed when needed.

6. Acoustic communication can be unreliable if operated in water depth that differs significantly from the design criteria (e.g. in water that is either much shallower or much deeper than the design range). Signal intensity varies significantly with water depth. An acoustic system optimized for 4,000 feet may be too loud at 1,000 feet and have insufficient amplitude at 7,000 feet. Acoustic systems can be adjusted for water depth. However, many rigs don't have the tools or technical training to do so.
7. Many drilling companies do not use acoustic systems unless mandated by regulation because of high cost and perceived high failure rates.

Ways to reduce the risk of existing Acoustic systems:

1. Verify hydrophone selection and source level setting are suitable for expected water depth and high noise levels.
2. Subsea hydrophones or relay beacons deployed by ROV 100 meters from the BOP stack could substantially improve communication during high well flow situations or when a gas or mud plume exists.
3. A free fall "depth charge" beacon can be dropped next to the BOP – and thus below any plume - to operate a desired function or set of functions.
4. Procedures should be put in place to deploy the hydrophones any time the stack is subsea.
5. An aggressive between well maintenance system is critical to reliable operation.

6.9 EHBU

An EHBU system is a hard-wired backup system to the primary MUX control system. Possible shortcomings of this system include the following:

1. This system is not stand alone, and separation of the riser or similar occurrence would make the system inoperable.

Means to reduce the risk of existing EHBU systems:

1. The addition of a deadman system would improve the reliability of the system. The deadman should be designed in such a way as to fill the role of an autoshear.

6.10 ROV Intervention

Possible shortcomings of this system include the following:

1. An ROV should not be used for secondary intervention unless the well is benign (non flowing) or unless it can be demonstrated that the designated functions can be performed in the API recommended time.
2. If not already in the water ROV deployment will require a long time, possibly long enough that the rams become unusable due to erosion damage, depending on the well flow rate.

3. Even if the ROV is at the stack, it can usually handle only one tool at a time and most likely won't have the stab needed to effect closure of the ram. In this case deployment time will be twice as long as it would be if the ROV were at the surface, as it will have to travel to the surface to obtain the correct tool and return to the stack before closure of the ram could begin.
4. Often the ROV is capable of operating the shear ram only. Should a serious leak occur through the failsafe valves, there would be no way to isolate the valve from the pressure.
5. ROVs cannot be deployed in rough weather.
6. ROVs have limited use in high current conditions.
7. Some ROV systems have high downtime rates, and therefore may not be available for secondary intervention when needed.

Means to reduce the risk of existing ROV systems:

1. Utilizing subsca accumulators as a hydraulic supply source could allow the ROV to operate a ram within the API specified time frame. This could be accomplished by either utilizing existing stack mounted accumulators or by adding a bank of dedicated accumulators that could be lowered to and retrieved from the sea floor independent of the stack. Note that accumulators on the LMRP would be useless in the event the LMRP were disconnected.
2. Function testing of the ROV system prior to running the stack should be performed. The functions should be operated at the same pressures and flow rates as capable by the ROV.
3. A wellbore test should be conducted after closing, locking and venting the ram as described above. A wellbore test is the only acceptable method of proving the function was operated correctly.
4. The lower pipe ram should be considered the master valve, and ROV intervention should be available to execute that function. Note that the drill pipe would have to be in the ram bore for this to be effective.

6.11 Summation

The variety and permutations of secondary systems are significant. Evaluation and use of the system(s) installed on a given rig requires an understanding of the failure modes, which it can mitigate. Risk/reward analyses can then determine adequacy of a rig's system for a particular drilling program.

7 Recommended Best Practices

Best practice recommendations depend on the type of control system – multiplex or hydraulic. Within the class of multiplex equipped rigs, considerations should be given to whether they are operating in DP or moored mode.

Note that for most of the systems discussed in this section the most significant cost factor is the requirement for dedicated accumulators with sufficient volume and pressure capability to operate the required functions. Many deepwater multiplex controlled stacks already have dedicated accumulators for some functions, which will reduce the cost of upgrading the system significantly.

Most of the shallow water, hydraulically piloted systems also have subsea accumulators installed, but these are used by the primary control system and are not dedicated to secondary intervention. It may be possible to reduce costs to these shallow water rigs by developing a design that incorporates existing subsea accumulators.

All operations should also incorporate mitigation of deficiencies noted in section 6. These were not included in this section to avoid redundancy.

7.1 Rigs with Multiplex BOP Control Systems

DP mode operation:

- EDS system
- Deadman

An EDS is a standard feature that all DP rigs have in common. The features of a “Deadman” system are recommended to supplement the EDS system, adding the capabilities of automatically containing the well if the LMRP is accidentally disconnected and/or the riser and cables part.

If a rig were already equipped with an AMF system, the addition of an Auto Shear circuit would be most beneficial and would be inexpensive to incorporate because the dedicated accumulators for this system will already be in place. The autoshear would secure the well in the event of an accidental or intentional disconnect of the LMRP, and the AMF would secure the well if the riser is parted.

An ROV would be required to manually secure a non flowing well.

Moored mode operation:

- Deadman

Because of the decreased likelihood of loss of station, a risk/reward analysis suggests eliminating or bypassing the EDS and auto disconnect functions when operating in this mode.

Again, if a rig were already equipped with an AMF system, the addition of an Auto Shear circuit would be most beneficial. An ROV would be required to manually secure a non flowing well.

7.2 Rig with Hydraulic control systems

Auto shear

The MMS has addressed the risk of accidental disconnect in NTL 2000-G07. The addition of an auto shear circuit is recommended to provide the automatic closure of the well in the event another cause accidentally unlatches the LMRP.

This is the class of rig that would benefit most from an improved design that incorporated the use of existing subsea accumulators.

Past practice has been to not combine components from the primary control system with those of secondary intervention. However, the line between primary and secondary systems is already becoming blurred due to control system manufacturers combining components in both type systems as a method of controlling cost.

MMS guidance on this matter could be very beneficial to the industry.

Again, an ROV would be required to secure a non flowing well.

7.3 All Rigs

- Any system designed to shear pipe must be demonstrated to be capable of shearing the pipe.
- Drill pipe tool joint placement at the time the shear activity occurs is critical.
- If a secondary intervention system is added to an existing system, a risk analysis should be performed to ensure the design is compatible and functionality optimal.
- MMS guidance should be provided concerning arming of secondary intervention systems.
- ROV capability as a means of secondary intervention should include the ability to utilize subsea accumulators as a supply source in order to ensure the designated functions can be performed in the API recommended time.
- Monitoring of the status of secondary intervention systems is desirable.
- Acoustic systems are not recommended because they tend to be very costly, and there is insufficient data available on system reliability in the presence of a mud or gas plume. However, acoustic communication in the form of verification of system status and remote arming should be considered.