Guidelines for Drilling Equipment

To ensure flexibility and clarity within the regulatory regime, these Guidelines create a framework for activities in the Newfoundland and Labrador offshore area. The Guidelines provide specific direction where the Board has been given the authority to prescribe and guidance where the Board may approve certain activities. Further, direction is also given on how the Board interprets the broadly-based legislative requirements governing the offshore area. To ensure responsiveness, these Guidelines may be reviewed from time to time, and where necessary, updated. As part of any planning process for activity in the offshore area, contact should be made with the appropriate departments of the Board to confirm the status of any particular Guideline and any legislative requirements.

Foreword

This document has been prepared to assist persons contemplating drilling in the Newfoundland offshore area in meeting the requirements of Section 15 – Requirements for Drilling Installations – and Section 21 - Standards for Drilling Equipment - of the Newfoundland Offshore Petroleum Drilling (Newfoundland) Regulations. The Canada-Newfoundland Offshore Petroleum Board intends to assure itself that drilling equipment proposed for use in works or activities authorized by the Board pursuant to Section 138 of the Canada-Newfoundland Atlantic Accord Implementation Act and Section 133 of the Canada-Newfoundland Atlantic Accord Implementation (Newfoundland) Act, meets these requirements.

All drilling installations operating in the Newfoundland offshore area are now required to have a Certificate of Fitness issued by a recognized Certifying Authority. The Board expects that the Certifying Authority will employ this document to assess the drilling equipment. The Certificate issued will attest that the installation to which it refers complies with these standards and requirements.

Introduction

The standards, codes and recommended practices referenced in these guidelines are the most recent editions at the time of publication. Any amendments or subsequent editions to any of these codes, standards or recommended practices will supersede the version specified herein, unless otherwise stipulated by the Chief.

A standard or quality assurance program other than that stipulated in this document may be used for design and construction of a drilling installation, if it is accepted by the Chief as providing a level of safety at least as high as that of the standard it replaces.

For drilling units built prior to publication of these guidelines, records regarding standards used in the design and the quality assurance program employed may, in some cases, not be available. Such equipment may be accepted by the Chief provided:

i. the manufacturer of the equipment has an established reputation;
ii. the work history of the equipment is known and the equipment has functioned without major malfunction throughout its life;

iii. any major malfunctions have been repaired using accepted standards and an approved quality assurance program;
iv. a quality assurance program is currently in place for maintenance and repair of the equipment; and,
v. inspections of blowout preventer equipment and overhead hoisting equipment, as required by this document, have been performed.

These conditions extend only to standards and quality assurance programs employed; all other requirements of this document should be met.

The certifying authority will assess the pressure rating of the well control equipment installed on an installation in accordance with the American Petroleum Institute standards referred to in this document and will specify this rating on the Certificate of Fitness. The weight rating of the hoisting system will also be specified on the Certificate of Fitness.

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1. LIST OF REFERENCED STANDARDS

1.1 Corrosion/Sulphide Stress Cracking

- National Association of Corrosion Engineers **Sulphide Stress Cracking Resistant Metallic Materials for Oilfield Equipment**, NACE Standard MR-01-75, January, 1984.

1.2 Quality Assurance

- Canadian Standards Association **Quality Assurance Program Requirements**, CAN 3-Z299.1-85, August, 1985;
- Canadian Standards Association **Quality Control Program Requirements**, CAN 3-Z299.2-85, August, 1985;
- Canadian Standards Association **Quality Verification Program Requirements**, CAN 3-Z299.3-85, August, 1985;
- Canadian Standards Association **Inspection Program Requirements**, CAN 3-Z299.4-85, August, 1985;
- Canadian Standards Association **Guide for Selecting and Implementing the CSA Z299-85 Quality Program Standards**, CAN 3-Z299.0-86, November, 1986.

1.3 Derrick and Substructure

- American Petroleum Institute **Drilling and Well Servicing Structures**, API Spec 4F, First Edition, May, 1985.

1.4 Drilling Line

- American Petroleum Institute **Specification for Wire Rope**, API Spec 9A, Twenty-third Edition, May, 1984.
- American Petroleum Institute **Recommended Practice on Application, Care and Use of Wire Rope for Oilfield Service**, API RP 9B, Ninth Edition, May, 1986.

1.5 Drawworks, Crown Block and Travelling Block

- American Petroleum Institute **Specification for Drilling and Production Hoisting Equipment** , API Spec 8A, Eleventh Edition, May, 1985.
- American Petroleum Institute **Recommended Practice for Hoisting Tool Inspection and Maintenance Procedures**, API RP 8B, Fourth Edition, April, 1979.
- American Petroleum Institute **Specification for Drilling and Production Hoisting Equipment (PSL 1 and PSL 2)**, API Spec 8C, First Edition, January, 1990.

1.6 Well Control System

- American Petroleum Institute **Specification for Wellhead and Christmas Tree Equipment** , API Spec 6A, Sixteenth Edition, October, 1989.
- American Petroleum Institute **Specification for Drill Through Equipment**, API Spec 16A, First Edition, November, 1986.
- American Petroleum Institute **Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells**, API RP 53, Second Edition, May, 1984.

1.7 Maintenance of BOP Stacks

- American Petroleum Institute **Specification for Wellhead and Christmas Tree Equipment** , API Spec 6A, Sixteenth Edition, October, 1989.
- American Petroleum Institute **Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells**, API RP 53, Second Edition, May, 1984.

1.8 BOP Stack Control System

- American Petroleum Institute **Specification for Control Systems for Drilling Well Control Equipment**, API Spec 16D, First Edition, March 1, 1993;

- American Petroleum Institute **Recommended Practice for Design of Control Systems for Drilling Well Control Equipment**, API RP 16E, First Edition, October 1, 1990.
- American Petroleum Institute **Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells**, API RP 53, Second Edition, May 1984.

1.9 Choke and Kill Lines and Choke Manifold

- American Petroleum Institute **Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells**, API RP 53, Second Edition, May, 1984.
- American National Standards Institute/American Society Mechanical Engineers **Chemical, Rig and Petroleum Refinery Piping**, ANSI/ASME B31.3, 1987.
- American Petroleum Institute **Specification for Wellhead and Christmas Tree Equipment**, API Spec 6A, Sixteenth Edition, October, 1989.
- American Petroleum Institute **Specification for Rotary Drilling Equipment**, API Spec 7, Thirty-seventh Edition, April, 1989.
- American Petroleum Institute **Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems**, API RP 14E, Fourth Edition, April, 1984.
- American Petroleum Institute **Specification for Choke and Kill Systems**, Spec 16C, First Edition, December, 1992.

1.10 Diverter System

- American Petroleum Institute **Recommended Practices for Diverter Systems Equipment and Operations**, API RP 64, January, 1991.

1.11 Diverter Control System

- American Petroleum Institute **Specification for Control Systems for Drilling Well Control Equipment**, API Spec 16D, First Edition, March 1, 1993; and
- American Petroleum Institute **Recommended Practice for Design of Control Systems for Drilling Well Control Equipment**, API RP 16E, First Edition, October 1, 1990.

1.12 Atmospheric Degasser

- American Society of Mechanical Engineers **Boiler and Pressure Vessel Code**, ASME, December, 1989.

1.13 Marine Riser System

- American Petroleum Institute **Recommended Practice for Design and Operation of Marine Drilling Riser Systems**, API RP 2Q, Second Edition, April, 1984.
- American Petroleum Institute **Recommended Practice for Design, Rating and Testing of Marine Drilling Riser Couplings**, API RP 2R, First Edition, May, 1984.

2. DEFINITIONS

2.1 **Chief** means the Chief Safety Officer.

2.2 **Critical Equipment** means any component or system of a drilling rig, the failure or malfunction of which, could create a hazard to the safety of personnel or jeopardize the security of the well.

2.3 **Drilling Rig** means the plant used to make a well by boring or other means and includes a derrick, draw works, rotary table, mud pump, blowout preventer, accumulator, choke manifold and other associated equipment including power, control and monitoring systems.

2.4 **Drilling Unit** means a drill ship, submersible, semi-submersible, barge, jack-up or other vessel used in a drilling program and fitted with a drilling rig, and includes the drilling rig and other facilities related to the drilling program that are installed on the vessel or platform.

2.5 **Drill Ship** means a ship that has a hull and is fitted with a drilling rig so that it is capable of drilling in deep water..

2.6 **Drilling Base** means the stable foundation on which a drilling rig is installed and includes a platform fixed to or resting on the seafloor.

2.7 **Drilling Installation** means

a. a drilling unit, or
b. a drilling rig and its drilling base.

2.8 **Drilling Program** means a program for the drilling of one or more wells within a specified area and time using one or more drilling installations and includes all operations and activities ancillary to the program.

2.9 **Drilling Program Authorization** means the authorization given to a person pursuant to paragraph 138 (1)(b) and paragraph 133(1)(b) of the *Canada-Newfoundland Atlantic Accord Implementation Act* and the *Canada-Newfoundland Atlantic Accord Implementation (Newfoundland) Act,* respectively, to conduct a drilling program.

2.10 **New Drilling Rig or Equipment** means any drilling rig or equipment installed on a platform after the coming into force of these standards and requirements.

2.11 **Operator** means an individual or company that has applied for or has been granted a Drilling Program Authorization.

3. REQUIREMENTS FOR DRILLING EQUIPMENT

3.1 General

3.1.1 All equipment of a drilling rig should be:

a. designed, fabricated, installed and maintained to operate safely and efficiently under the most unfavourable combination of load conditions and loading cycles anticipated during the life of the drilling equipment; [Ref: DR 15(b)]
b. so arranged that
    i. it is accessible and safe for operation and maintenance, and
    ii. in the event of failure of a piece of equipment, the failure does not, to the extent practicable, result in subsequent failure of critical equipment;
c. compatible in terms of function, capacity and strength;
d. protected from excessive loads, to the extent that this is practicable.

3.1.2 All equipment located in hazardous areas should be designed and equipped for operation in those areas.

3.1.3 All equipment should be designed, constructed and equipped for the environmental conditions to which they may be exposed during the drilling program, [Ref: DR 15(a)] including:

a. the 100-year return period storm;
b. temperature extremes;
c. exposure to moisture, icing conditions and salt-laden spray.

3.1.4 Any critical equipment which is subjected to a load or pressure greater than its working load or working pressure should be either

a. inspected for damage and determined to be safe for continued use; or
b. replaced with equipment with the necessary load or pressure capacity.

3.1.5 All critical equipment should

a. be protected from corrosion to prevent loss of strength or function; and
b. meet the requirements of the National Association of Corrosion Engineers **Sulphide Stress Cracking Resistant Metallic Materials for Oilfield Equipment** NACE Standard MR-01-75, January, 1984, if the components may be exposed to hydrogen sulphide.

3.1.6 Every owner of a drilling installation should ensure that a risk analysis of the design and lay out of equipment is conducted to identify any potential hazards and

a. in the case of a new drilling installation, to ensure that the lay out of critical equipment and the routing of electrical, hydraulic or pneumatic control lines to critical equipment has been arranged so as to reduce, to the maximum extent practicable, the risk from the identified hazards; and

b. in the case of an existing drilling installation, to ensure that the risk from the identified hazards is reduced, to the maximum extent practicable, by providing additional protection or redundancy to critical equipment, devising appropriate operational or emergency procedures or taking such other steps as may be necessary to reduce the risk.

3.1.7 A report summarizing the findings and recommendations of the risk analysis referred to in section 3.1.6 should be provided to the Chief with the application for a Drilling Program Authorization.

3.1.8 The design, fabrication, construction, installation and commissioning of all components of a drilling rig should be performed in accordance with the Canadian Standards Association **Quality Assurance Program Standards**, CAN3-Z299-85, August, 1985.

3.1.9 The quality assurance program for the equipment of a drilling rig should be determined by the application of Canadian Standard Association **Guide for Selecting and Implementing CAN3-Z299-85 Quality Assurance Program Standards**, CAN3-Z299.0-86, November, 1986.

3.1.10 Each drilling installation should be provided with up-to-date copies of operating manuals, equipment specifications, drawings and any other information necessary for the operation, maintenance and repair of all critical equipment. [Ref: DR 63(1)]

3.1.11 For each drilling installation a planned maintenance program should be devised and implemented for all critical equipment and records of maintenance activities pursuant to the program should be kept on-board the installation.

3.1.12 Operating manuals and planned maintenance programs should be updated regulatory based on notices of revised operating procedures and equipment modifications from equipment suppliers, and notices to operators which may be issued by the Board from time to time.

3.1.13 Where more than one drilling rig is installed on an installation, critical equipment should not be shared between the drilling rigs unless the operator demonstrates, to the satisfaction of the Chief, that the sharing of the critical equipment will not result in an unacceptable level of risk to the safety of personnel or the security of a well.

3.1.14 The accuracy of all pressure gauges associated with circulating, well control and cementing equipment should be established by means of comparison with a deadweight tester at least annually, with calibration records maintained on board the installation for at least one year.

3.1.15 Pressure gauges found to have an accuracy less than 2% of full scale should be repaired or replaced.

3.1.16 Equipment which does not meet the requirements of these standards may be installed temporarily on the drilling installation, provided that

a. the type of equipment or its location does not increase the risk to personnel or the security of the well; or,
b. the function of other equipment installed on the drilling installation is not impaired so as to increase the risk to personnel or the security of the well.

3.2 Rotary, Hoisting and Pipe Handling System

3.2.1 The derrick and substructure shall be designed and constructed in accordance with American Petroleum Institute **Specification for Drilling and Well Servicing Structures** , API Spec 4F, First Edition, May, 1985, except as otherwise stipulated by these requirements.

3.2.2 The derrick and substructure should be designed.

a. to take into account increased dead-load and wind induced load due to the accumulation of ice and snow;
b. to take into account loading due to fastener prestress;
c. where it is anticipated that operational conditions warrant, with a setback load greater than indicated in API Spec 4F;
d. where the operator anticipates operations will be conducted at wind speeds higher than indicated in API Spec 4F, to withstand at least the maximum wind speed at which operations will be conducted;
e. such that the static and, in the case of floating drilling installations, dynamic loadings which form the basis for the design equal or exceed the loads which may be imposed on the derrick during the drilling program.

3.2.3 Allowable unit stresses for derricks should not be increased as suggested by section 7.2.1 or 7.2.2 of API Spec 4F unless approved by the Chief.

3.2.4 If the derrick is manned, it shall be equipped with an escape device to permit personnel at the monkey board level to escape to a point outside the derrick structure. [Ref: DR 25a]

3.2.5 The design and maintenance of wire rope used as a drilling line should comply with

- American Petroleum Institute **Specification for Wire Rope**, API Spec 9A, Twenty-third Edition, May, 1984; and
- American Petroleum Institute **Recommended Practice on Application, Care and Use of Wire Rope for Oilfield Service**, API RP 9B, Ninth Edition, May, 1986.

3.2.6 The drawworks, crown block, travelling block and ancillary equipment should be designed in accordance with

- American Petroleum Institute **Specification for Drilling and Production Hoisting Equipment**, API Spec 8A, Eleventh Edition, May, 1985; and
- American Petroleum Institute **Recommended Practice for Hoisting Tool Inspection and Maintenance Procedures**, API RP 8B, Fourth Edition, April, 1979;
- American Petroleum Institute **Specification for Drilling and Production Hoisting Equipment (PSL 1 and PSL 2)**, API Spec 8C, First Edition, January, 1990.

3.2.7 The overhead hoisting system should be subject to:

a. annual non-destructive testing, intended to detect cracks, on all visible critical areas and components; and
b. a full tear-down of the equipment every four years.

3.2.8 Inspection reports pursuant to subsection 3.2.7 should be kept on-board the drilling installation for a period of at least one year.

3.2.9 The drawworks should be provided with a safety device to prevent the travelling block from striking the crown of the derrick.

3.2.10 The drawworks should be fitted with an auxiliary brake to assist the primary braking system.

3.2.11 The auxiliary brake should be equipped to monitor level, flow and temperature of the cooling or operating fluid in a manner which assures serviceability of the auxiliary brake.

3.2.12 The hook latch should be designed to prevent release of the drill string when subjected to a sharp upward blow.

3.2.13 In the case of a new drilling installation, the drawworks should be equipped with an automatic fail-safe system capable of stopping a full load if a fault is detected in the primary or auxiliary brake system.

3.2.14 Alarms should be provided at the driller's station to indicate when

a. the limiting parameters for the auxiliary braking system have been reached, and
b. the system referred to in section 3.2.13 has been activated.

3.2.15 Mechanized equipment including power tongs and a pipe spinner capable of making-up, breaking-out and torquing drill pipe connections should be installed on the drilling installation.

3.2.16 In the case of floating drilling installations

a. the pipe handling equipment for racking drill pipe in the derrick should be mechanized, unless otherwise approved by the Chief; and
b. the drill string motion compensator should
    i. in the locked position, have a load rating at least equivalent to that of the hoisting system,
    ii. in the operating position, have a dynamic load rating sufficient to meet the maximum load requirements for drilling and other operations requiring the use of the motion compensator.

3.3 Well Control System

3.3.1 Except as otherwise stipulated herein, the well control system should be designed, constructed and configured in accordance with

- American Petroleum Institute **Specifications for Wellhead and Christmas Tree Equipment** , API Spec 6A, Sixteenth Edition, October, 1989.
- American Petroleum Institute **Specification for Drill Through Equipment**, API Spec 16A, First Edition, November, 1986; and
- American Petroleum Institute **Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells**, API RP 53, Second Edition, May, 1984.

3.4 Blowout Preventer Stack and Control System

3.4.1 The blowout preventer stack shall have sufficient structural strength to withstand any combination of static and dynamic loads, both axially and laterally applied, which may reasonably be anticipated, acting simultaneously with the maximum rated working pressure determined pursuant to sections 3.3.1. [Ref: DR 47(a)]

3.4.2 The blowout preventer stack should have a rated working pressure that is in every case equal to or greater than 2,000 psi (13,790 KPa). [Ref: DR 46(5)& 81(1)(a)]

3.4.3 The working pressure of the annular preventer(s), and, on a subsea stack, the upper hydraulic connector, if it is located below the annular preventer(s), need not exceed 5,000 psi (34,474 KPa) if the rated working pressure of the blowout preventer stack is equal to or less than 10,000 psi (68,948 KPa). [Ref: DR 46(4)].

3.4.4 Each ram type preventer should be equipped with a hydraulic or electrohydraulic controlled or automatic mechanical locking device capable of locking the rams in the closed position on all

a. sub-sea blowout preventer stacks; and
b. surface blowout preventer stacks on production platforms where the required pressure rating of the stack is greater than 3,000 psi (20,684 KPa).

3.4.5 The lower marine riser package on every dynamically positioned drilling installation should be equipped with a high-angle release connector capable of disconnecting from the blowout preventer stack at flex joint angles of at least 10 degrees.

3.4.6 All flanges and hub connections used in the blowout preventer stack, choke and kill lines and choke manifold shall be equipped so as to provide a full metal-to-metal seal, equivalent to that provided by ring joint gaskets.

3.4.7 Every sub-sea blowout preventer stack should consist of the following components:

a. a hydraulic or electrohydraulic controlled connector capable of providing a reliable means of connecting to and disconnecting from the well-head; [Ref: DR 46(3)]
b. at least one hydraulic or electrohydraulic controlled annular type preventer; and
c. at least one set of hydraulic or electrohydraulic controlled ram-type preventers capable of
    i. shearing any size and weight of drill pipe in use and subsequently sealing the well-bore, and
    ii. cutting the drill pipe in such a manner as to enable circulation through the drill pipe after it has been sheared;
d. one set of hydraulic or electrohydraulic controlled ram-type preventers capable of sealing around the drill pipe in use, and allowing the drillpipe to be stripped into or out of the well in an emergency situation; and,
e. such additional equipment as the Chief may require for the purposes of ensuring the safety of personnel or the security of the well.

3.4.8 Sub-sea blowout preventer stacks with a rated pressure greater than 3,000 psi (20,684 KPa) and less than 10,000 psi (68,948 KPa) should, in addition to the requirements of section 3.4.7, include at least one additional set of hydraulic or electrohydraulic controlled ram type preventers capable of allowing the drillpipe to be stripped into or out of the well in an emergency situation.

3.4.9 Sub-sea blowout preventer stacks with a rated pressure 10,000 psi (68,948 KPa) or greater should, in addition to the requirements of section 3.4.7, include:

a. an additional annular-type preventer which may be installed either on the lower marine riser package or on the blowout preventer stack; and
b. at least two additional sets of hydraulic or electrohydraulic controlled operated ram type preventers capable of allowing the drill pipe to be stripped into or out of the well in an emergency situation.

3.4.10 Blowout preventer stacks for jack-up drilling installations and production installations with a rated pressure of 3,000 psi (20,684 KPa) or less should consist of the equipment referred to in paragraphs 3.4.7 (b) to (e).

3.4.11 In addition to the requirements of section 3.4.10, blowout preventer stacks for jack-up drilling installations and production installations with a rated pressure greater than 3,000 psi (20,684 KPa) and less than 10,000 psi (68,948 KPa), should include at least one additional set of hydraulic or electrohydraulic controlled ram-type preventers capable of allowing the drillpipe to be stripped into or out of the well in an emergency situation.

3.4.12 Blowout preventer stacks for jack-up drilling installations and production installations with a rated pressure of 10,000 psi (68,948 KPa) or greater should, in addition to the requirements of section 3.4.10, include at least two additional sets of hydraulic or electrohydraulic controlled ram-type preventers capable of allowing the drillpipe to be stripped into or out of the well in an emergency situation.

3.4.13 When drilling with a tapered drill string, at least one of the ram type preventers should be a variable bore ram capable of sealing around each size drill pipe in use.

3.4.14 For sub-sea blowout preventer stack

a. blind/shear rams should be installed in the uppermost ram body.
b. at least one of the ram type preventers installed below the blind/shear rams should be designed to
    i. accommodate hang-off of the drill string on a tool joint, and
    ii. support the weight of the heaviest drilling assembly in use; and
c. sufficient clearance should be provided between the designated hang-off rams and the blind and the blind/shear rams so that a tool joint does not interfere with the closing of the blind/shear rams when the drill string is hung off.

3.4.15 Choke and kill outlets on sub-sea blowout preventer stacks should be arranged such that

a. with any blowout preventer closed, except the lower rams, there is a circulation route for fluids from the well annulus through a choke or kill line, and an alternate circulation route out of the well through another choke or kill line;
b. the well may be circulated via the drill string using the choke/kill lines when the drill pipe has been hung off and sheared; and
c. there is no more than one outlet in use between adjacent preventers and below the lower rams.

3.4.16 At least two valves should be installed on each choke and kill outlet, one of which should be a hydraulic or electrohydraulically controlled valve which should fail safe in all conditions of flow rate and drilling fluid type and weight which may reasonably be expected during any well operations.

3.4.17 In the case of a sub-sea blowout preventer stack, both valves installed on each choke and kill outlet should be remotely operated fail-safe valves.

3.4.18 The fail-safe valves referred to in sections 3.4.16 and 3.4.17 should be protected from falling objects by being located as close to the body of the stack as practicable.

3.4.19 Every blowout preventer stack should be overhauled and tested every four years in accordance with American Petroleum Institute **Specification for Wellhead and Christmas Tree Equipment**, API Spec 6A, Sixteenth Edition, October, 1989 and American Petroleum Institute **Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells**, API RP 53, Second Edition, May, 1984 unless the operator provides data to show the overhaul and testing is unnecessary.

3.4.20 Except as otherwise stipulated, the control system for the blowout preventer stack should be designed, constructed and arranged in accordance with

- American Petroleum Institute **Specification for Control Systems for Drilling Well Control Equipment**, API RP 16D, First Edition, March 1, 1993; and
- American Petroleum Institute **Recommended Practice for Design of Control Systems for Drilling Well Control Equipment**, API RP 16E, First Edition, October 1, 1990; and
- American Petroleum Institute **Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells**, API RP 53, Second Edition, May, 1984.

3.4.21 The main electrical control panel or hydraulic control manifold unit of the blowout preventer control system should be located such that it is protected from fire or explosion originating in the well-head, drill floor or spider deck areas and should be easily accessible from outside the well-head, spider deck or drill floor areas.

3.4.22 In addition to the primary control panel located in the driller's cabin the blowout preventer control system must be equipped with a secondary control panel located in a suitably protected location that is easily and quickly accessible by supervisory drilling personnel. [Ref: DR 46(a) & (b)]

3.4.23 Surface hydraulic control lines should be routed to protect them from fire or explosion damage to the maximum extent practicable.

3.4.24 Pressure regulators on the main control manifold unit of the blowout preventer system should have a backup air supply or should be of a type which permits hydraulic pressure delivered to blowout preventer functions to be maintained following loss of the primary source of pressurized air for the operation of the regulators.

3.4.25 The system to be used for the operation of the remote control panels on the BOP system may be either the electric or electro-hydraulic type.

3.4.26 The blowout preventer control system on dynamically positioned drilling units should be equipped with an automatic sequencing system whereby all functions necessary to close shear rams and disconnect the lower marine riser package are automatically performed in the correct order by activating a single function on the control panel.

3.4.27 The requirements of sections 3.4.7 to 3.4.12 are summarized in the following table:

TYPE & PRESSURE RATING OF BLOWOUT PREVENTER STACK

	SUB-SEA				**JACKUP/PLATFORM (SURFACE)**			
PRESSURE RATING	2K,3K	5K	10K,15K 20K		2K,3K	5K,10K	15K,20K	
			OR				OR	
ANNULAR	1	1	2	2	1	1	1	1
PIPE	1	2	3	2	1	2	3	2
BLIND/ SHEAR	1	1	1	2	1	1	1	2

K=1,000 psi rated working pressure

3.5 Choke and Kill Lines and Choke Manifold

3.5.1 Choke manifolds and choke and kill lines should be designed in accordance with good engineering practices having regard for:

a. maximum and minimum anticipated temperatures;
b. the abrasive nature of well fluids;
c. dynamic forces caused by the flow of well fluids; and
d. any other phonomena caused by the flow of well fluids including vibrational stresses, pressure pulsation and temperature variations that may have a detrimental effect on the structural integrity of the manifold, choke lines and kill lines.

3.5.2 Except as otherwise stipulated by these requirements, the choke and kill lines and choke manifold should be designed, constructed and arranged in accordance with

- American Petroleum Institute **Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells**, API RP 53, Second Edition, May, 1984;
- American Petroleum Institute **Specification for Choke and Kill Systems**, Spec 16C, First Edition, December, 1992; and
- American Petroleum Institute **Specification for Wellhead and Christmas Tree**

Equipment, API Spec 6A, Sixteenth Edition, October, 1989.

3.5.3 Except as otherwise stipulated by these requirements the choke and kill lines, the choke manifold piping system and all other high pressure piping systems shall comply with

- American National Standards Institute/American Society Mechanical Engineers **Chemical, Rig and Petroleum Refinery Piping**, ANSI/ASME B31.3-1987.
- American Petroleum Institute **Specification for Rotary Drilling Equipment**, API Spec 7, Thirty Seventh Edition, April, 1989; and
- American Petroleum Institute **Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems**, API RP 14E, Fourth Edition, April, 1984

3.5.4 For high strength piping materials and wall thickness ratios not covered by the codes referenced in section 3.5.3 alternate design criteria acceptable to the Chief may be employed.

3.5.5 The working pressure of the choke and kill lines, choke manifold and all components up to and including the first valve downstream of each choke should be determined in accordance with Subsection 3.5.2.

3.5.6 The choke and kill lines should be arranged such that drilling fluid may be pumped into the well through either the choke line or the kill line and simultaneously circulated out of the well through the other choke or kill line.

3.5.7 The choke and kill lines should be clearly identifiable by colour coding or other suitable means.

3.5.8 The choke and kill lines, choke manifold and ancillary components should be protected from freezing.

3.5.9 The inside diameter of the choke and kill lines and all lines and valves comprising the choke manifold should be greater than 63 mm (2.5 in).

3.5.10 The choke manifold should be

a. placed in a readily accessible location for easy control and maintenance;
b. equipped with a clean-out, or gut line which connects the high and low pressure sides of the manifold;
c. where the rated working pressure is greater than 3,000 psi (20,684 KPa), equipped with at least three adjustable chokes;
d. configured such that while drilling fluid is being pumped down the choke or kill line using the mud pumps or the kill pumps, well fluid may be circulated up the opposite choke or kill line and directed through each of the chokes required pursuant to (c);

e. designed and arranged to permit replacement or repair of any one choke while simultaneously flowing through any of the other chokes;
f. capable of directing flow from any choke
    i. through mud-gas separation equipment and subsequently to the mud pits, and
    ii. through the overboard line referred to in section 3.5.14; and
g. equipped with accurate pressure gauges to measure the casing pressure and a sufficient number of outlets to permit, with the selection of any flow path, measurement of choke and kill line pressures.

3.5.11 The clean out line required pursuant to paragraph 3.5.10(b) should be equipped with at least two valves having a pressure rating at least equal to the pressure rating of the high pressure side of the choke manifold.

3.5.12 Where the choke manifold is located in an enclosed area the area should be adequately ventilated to prevent the concentration of combustible gases from accumulating to a dangerous level.

3.5.13 Every valve on the choke manifold should be clearly marked to indicate its normal position.

3.5.14 An overboard discharge line from the choke manifold should be installed which should

a. be as short and straight as possible with changes in direction minimized and all bends targeted be equipped with block tees to prevent erosion damage;
b. have a rated pressure at least equal to that of the low pressure side of the choke manifold; and
c. be capable of directing the flow of well fluids overboard to opposite sides of the drilling installation [Ref: DR 81a].

3.5.15 Notwithstanding subsection 3.5.14(c), a single overboard line may be used for the discharge of well fluids overboard from the choke manifold, where this configuration can be shown to provide at least the same level of safety.

3.5.16 All valves on at least one of the flow lines downstream of the choke manifold should be secured in the open position to prevent inadvertent over-pressuring of the low pressure lines and valves downstream of the choke manifold.

3.5.17 Accurate high and low pressure gauges that fit the outlets on the choke manifold should be available for immediate installation.

3.5.18 At least one of the adjustable chokes required pursuant to subsection 3.5.10(c) should be remotely controlled, with the control panel for operation of that choke installed at or in close proximity to the driller's position;

3.5.19 The choke control panel required pursuant to subsection 3.5.18 should provide a reliable measurement of

a. drill pipe pressure;
b. choke and kill line pressure;
c. pump stroke rate and total number of pump strokes of the pump used in the well kill operation; and
d. choke position.

3.5.20 Where a choke manifold installed on a floating platform has a rated working pressure greater than 10,000 psi (68,900 KPa), it should be equipped with

a. at least four adjustable chokes, two of which should be remotely controlled from the panel required pursuant to subsection 3.5.18;
b. a split buffer tank arranged such that
    i. one side of the tank may be isolated while well fluids are being circulated out through the opposite side;
    ii. at least one adjustable choke and one remote controlled choke discharge to each side of the buffer tank.

3.5.21 Detachable connections on choke and kill piping and manifolds should only be used where assembly and dismantling may be required.

3.5.22 Flexible lines should be used to connect lines which may contain hydrocarbons, including choke and kill lines, where

a. relative motion occurs between any elements of the drilling rig; or
b. connections are temporary.

3.5.23 Where flexible lines are used for choke and kill lines, these lines should

a. comply with American Petroleum Institute **Specification for Choke and Kill Systems**, API Spec 16C, First Edition, Dec., 1992.
b. have a rated pressure at least equal to that of the choke manifold system determined pursuant to subsection 3.5.5;
c. have an inside diameter at least equal to that of the choke and kill lines;
d. be capable of withstanding the maximum stresses which may be anticipated to result from the most unfavourable combination of the motion of the drilling installation, maximum internal pressure and maximum temperature to which the flexible lines are likely to be subjected;
e. have sufficient fatigue resistance to prevent loss of strength over the service life of the hose; and
f. for lines not submerged, capable of resisting fire for a sufficient period of time to shut in

the well in an orderly manner.

3.5.24 Notwithstanding the provisions of American Petroleum Institute **Specification for Choke and Kill Systems**, API Spec 16C, Flexible Lines, First Edition, December, 1992 the use of all steel articulated lines is not permitted for flexible connections on marine riser choke and kill lines or in any other application where the lines may contain pressurized formation fluids and motion between the two ends of the flexible line is of a continuous nature.

3.6 Diverter System

3.6.1 The diverter system should be designed, constructed and configured in accordance with American Petroleum Institute **Recommended Practice for Diverter Systems Equipment and Operations**, API RP 64, January, 1991 except as otherwise stipulated by these requirements.

3.6.2 The diverter system should be capable of withstanding the maximum anticipated combination of loads, both static and dynamic, resulting from the flow of gas and liquid, including thrust and shock loads from the initial burst of gas.

3.6.3 The overboard diverter lines should

a. be installed to permit fluid flow to be directed to at least two opposite sides of the installation;
b. be installed as straight as possible and should be securely tied down;
c. have a nominal diameter of not less than 305 mm (12 in);
d. where bends or branches cannot be avoided, be designed to allow for the erosive effect of solids entrained in the fluid flow; and
e. terminate to the atmosphere beyond the structure of the installation;
f. notwithstanding subsection (a), a single overboard line may be used for the diverter system, where this configuration can be shown to provide at least the same level of safety.

3.6.4 The diverter system should be designed and maintained such that one vent line is open at all times.

3.6.5 The control system for the diverter system should comply with

- American Petroleum Institute **Specification for Control Systems for Drilling Well Control Equipment**, API RP 16D, First Edition, March 1, 1993; and
- American Petroleum Institute **Recommended Practice for Design of Control Systems for Drilling Well Control Equipment**, API RP 16E, First Edition, October 1, 1990.

3.6.6 The control system for the diverter should be of a hydraulic type and should be arranged such that all operations to close the diverter and the shale shaker discharge line and open the diverter vent line can be accomplished by activating a single function on the diverter control panel.

3.7 High Pressure Kill Pumping System

3.7.1 Drilling installations should be equipped with a high pressure kill pumping system which should

a. be capable of pumping kill fluids at a pressure at least equal to the maximum anticipated injection pressure that may be encountered during well killing operations;
b. consist of at least two pumps with each pump being powered by either
   i. a dedicated internal combustion engine [Ref: DR 41], or
   ii. if electrically powered, also connected to a back-up power supply, independent of the main power supply; and
c. be equipped to allow the person operating the equipment to monitor the pressure, flow rate, and volume of the fluid being pumped.

3.7.2 The cement pumps referred to in paragraph 3.11.1 (f) may be used as the high pressure kill pumping system provided they meet the requirements of section 3.7.1.

3.7.3 Pumps required to transfer drilling fluid from the mud pits to the high pressure kill pumping system should also be connected to a back-up power supply, independent of the main power supply.

3.8 Ancillary Well Control Equipment

3.8.1 Every drilling installation should be equipped with ancillary well control equipment consisting of

a. except as provided by section 3.8.4, at least one high pressure circulating head and associated lines which should
   i. be capable of being safely and quickly connected to the drill pipe to permit fluids to be circulated down the drill pipe,
   ii. equipped with flexible lines and suitable connections capable of withstanding, where necessary, the motions of the drilling installation for extended periods while maintaining full pressure integrity;
b. valves that are installed immediately above and below the kelly and which should be designed to be safely and quickly closed by drill floor personnel;
c. at least two stabbing valves with appropriate cross-over subs to fit each type of connection in the drilling assembly which should be designed to be safely and quickly installed in the drilling assembly and closed to isolate and control pressure in the drill stem to allow the kelly or high pressure circulating head to be installed;
d. at least two back pressure valves which should
   i. be designed to permit their installation in the drilling assembly and to be stripped or snubbed into the well,
   ii. permit fluids to be circulated down the drilling assembly but prevent upward flow,
e. an inside blowout preventer capable of being installed near the bottom of the drilling assembly which seals off flow up the drill-stem after a pump-down dart assembly is installed;
f. a float valve capable of being installed at the bottom of the drilling assembly to prevent

flow up the drill-stem; and

g. in the case of a floating drilling installation, a hang-off tool which should
    i. be designed to be quickly made up to the drill pipe in use,
    ii. be capable of suspending the drilling assembly within or below the blowout preventer stack,
    iii. enable the drill pipe to be disconnected above the hang-off tool at a point below the blind/shear rams,
    iv. equipped with a back pressure valve or other pressure isolation device to restrict upward flow, but permit fluids to be circulated down the drill pipe, and
    v. enable the drill pipe to be efficiently reconnected to the suspended drilling assembly and allow circulation of fluids down the drill pipe.

3.8.2 All ancillary well control equipment that is an integral part of the drillstem should have:

a. A pressure rating at least equal to the pressure rating of the blowout preventer systems determined pursuant to subsection 3.3.1;
b. have a tensile strength at least equal to the drill pipe in use.

3.8.3 The flexible line required by Section 3.8.1(a)(iii) should meet the requirements of 3.5.23 and 3.5.24.

3.8.4 The high pressure circulating head referred to in paragraph 3.8.1 (a) is not required where the kelly and kelly hose have a pressure rating at least equal to the pressure rating of the blowout preventer systems determined pursuant to subsection 3.3.1.

3.8.5 Where a top drive drilling system is used in lieu of a kelly,

i. valves meeting the functional requirements of paragraph 3.8.1 (b), and providing an equivalent degree of safety, should be maintained in the drilling assembly; and
ii. at least one of the valves should be of a type which can be controlled from the driller's position.

3.8.6 Gauges with an accuracy of ±10 psi (68.9 KPa) should be available for measurement of shut-in drill pipe pressure and shut-in casing pressure.

3.9 Drilling Fluid System

3.9.1 The equipment required to prepare and contain the drilling fluid should consist of

a. liquid mud tanks with sufficient capacity and subdivisions to permit
    i. the on-board storage of active and reserve drilling fluid to meet all foreseeable normal and emergency operating requirements, and
    ii. drilling fluid properties to be adjusted in a controlled manner.

b. bulk tanks and storage facilities with capacity to permit the on board storage of adequate quantities of all bulk materials and drilling fluid additives which may be used in the drilling fluid system;
c. compressors, piping, surge tanks, hoppers and mixing equipment to permit the safe and efficient transfer, handling and mixing of all bulk materials and drilling fluid additives to be used in the drilling fluid system;
d. sufficient equipment to ensure the appropriate dryness of the air used in the transfer of bulk materials for the drilling fluid system;
e. equipment with sufficient capacity to increase the density of the drilling fluid, as required for well killing operations, by the direct addition of weighting material while circulating the well during the well kill operation;
f. sufficient redundancy in the equipment and in the layout of the equipment referred to in paragraph (c) to permit, with the plugging of any major line or the malfunction of any compressor or compressed air receiver or mixing device, the safe and effective transfer and mixing of weighting material to enable the density of the drilling fluid to be increased.

3.9.2 The liquid mud tank storage capacity shall be at least 180 m^3 or 50 percent of the aggregate of the hole volume or, in the case of a floating drilling installation, 50 percent of the hole volume and marine riser, whichever is the lesser. [Ref: DR 60(2)]

3.9.3 The equipment to circulate and condition the drilling fluid should consist of

a. at least two mud pumps which should
    i. be capable of circulating the well in a safe and effective manner at the maximum anticipated flow rate and pressure required for drilling operations, and
    ii. be equipped with pulsation dampers and safety relief valves;
b. the necessary pumps, piping, manifolding and valves to permit
    i. fluid to be drawn from any mud tank in use,
    ii. fluid to be pumped down either the drill pipe or the choke/kill lines, and
    iii. seawater to be supplied to any mud tanks in use;
c. the necessary shale shakers, desanders and desilter cyclones and centrifuges as appropriate for safe operations on the well, along with pumps, valves and interconnecting piping and manifolding laid out so as to enable the efficient removal of drill solids and undesired weighting material; [Ref: DR 60(1)(d)] and
d. mud-gas separation equipment consisting of
    i. an atmospheric degasser capable of removing entrained gas from the drilling fluid following discharge from the choke manifold,
    ii. a vacuum degasser or equivalent equipment located near the shale shakers capable of removing entrained gas from the drilling fluid returns from the well, and
    iii. vent lines installed on degassing equipment to discharge gas separated from the drilling fluid to a safe location.

3.9.4 The atmospheric degasser required by sub-paragraph 3.9.3 (d) i) should

a. be equipped with a pressure gauge to monitor the pressure in the separator;
b. employ a liquid mud seal which is at least 3 m in height to control the separator back-pressure;
c. be capable of being isolated in the event its capacity is exceeded during a well control

operation and it becomes necessary to dispose of the well fluids via one of the over-board discharge line referred to in section 3.5.14;

d. have a gas vent with a nominal diameter of at least 203 mm (8 in); and
e. where the separator is equipped with a "U tube" type of liquid mud seal, be equipped with a secondary vent installed on the "U-tube" seal which
    i. is fitted at the highest point of the pipe work,
    ii. has a nominal diameter of at least 152 mm (6 in), and which is not tied into the primary vent referred to in paragraph (d).
f. have a diameter of at least 36 in. (914 mm) and a height of at least 16 ft. (4.9 m);
g. have a working pressure of at least 150 psi (1034 Kpa);
h. be securely anchored down to resist the vibration and shock loading which may be associated with circulation of a gas kick through the degasser;
i. be designed in accordance with American Society of Mechanical Engineers **Boiler and Pressure Vessel Code**, Section VIII, Div. 1, Pressure Vessels, ASME, December, 1989.

3.9.5 The pressure gauge required by paragraph 3.9.4 (a) should have a display at, or be readily visible from the choke control position.

3.10 Drilling Fluid and Well Surveillance System

3.10.1 The drilling fluid and well surveillance system should be capable of measuring, recording and displaying drilling parameters which may indicate a hazard to personnel or affect the security of the well. [Ref: DR 14)]

3.10.2 The drilling fluid and well surveillance system should consist of

a. drilling fluid tank level indicators to alert personnel of gains or losses in the active system which, in the case of a floating drilling installation, are designed and installed to compensate, to the extent practicable, for vessel motion; [Ref: DR 60(3)(a)]
b. a tank to accurately determine the drilling fluid displaced from the hole and required to fill the hole during trips; [REF: DR 60(3)(b)]
c. a mud-return or full hole indicator that monitors drilling fluid returns; (Ref: DR 60(3)

    (c)]

d. hydrocarbon gas and hydrogen sulphide detectors to measure the
    i. gas content of the drilling fluid, [Ref DR 60(3)(e)]
    ii. gas content in the air at the bell nipple, shale shakers, active drilling fluid tanks, drill floor and choke manifold;
e. devices that automatically actuate audible and visual alarms to alert personnel of the presence of hydrogen sulphide or high concentrations of hydrocarbon gas
    i. in the drilling fluid [Ref: DR 60(3)(e)] and
    ii. in the areas specified in subparagraph (d) ii);
f. equipment capable of continuously measuring the
    i. well depth,
    ii. rate of penetration,
    iii. temperature of the return drilling fluid,
    iv. hook load, and

v. any other critical drilling parameters necessary for monitoring the safety and efficiency of the drilling operation such as rotary torque, rotary speed and weight-on-bit.

g. equipment to display the following parameters at the drillers station;

i. the pump stroke rate or flow rate of the mud pumps,
ii. the output, from the mud return or full hole indicator, [Ref: DR 60(3)(c), 60(4)]
iii. the volume of active fluid in the mud tanks [Ref: DR 60(3)(b), 60(4)]
iv. the volume of fluid in the trip tank,
v. the standpipe pressure,
vi. hook load,
vii. weight-on-bit,
viii. rate of penetration,
ix. rotary torque, and
x. any other equipment, drilling fluid and well parameters considered critical to the safety of the drilling operation;

h. equipment to record permanently the well depth and the parameters from the driller's station referred to in subparagraphs (g) i), iii) and v) to ix);

i. audible and visual alarms at the driller's station, and at the mudlogging location referred to in paragraph 3.10.3 to warn of

i. an increase above or decrease below pre-set limits of the level of fluid in the drilling fluid tanks,
ii. an increase above or decrease below pre-set limits of the drilling fluid return indicator, and
iii. the presence of toxic or combustible gases.

3.10.3 A mudlogging unit should be positioned at a location remote from the driller's station and manned continuously by dedicated monitoring personnel to measure the following parameters:

i. the amount and composition of any hydrocarbon gases present in the return drilling fluid,
ii. the depth of the well,
iii. the density of the drilling fluid,
iv. the temperature of the return drilling fluid,
v. the parameters referred to in subparagraphs 3.10.2(g) i) and iii) to ix) above.

3.10.4 Notwithstanding subsection 3.10.3, the mud logging unit may not be required on a production drilling installation after four development wells have been drilled on a field.

3.10.5 The parameters displayed and monitored at the mudlogging location referred to in subparagraph 3.10.3 should be periodically and permanently recorded.

3.10.6 Audible and visual alarms should be installed on the drilling installation to warn of the presence of toxic or combustible gases.

3.10.7 On each drilling rig equipment should be available to manually measure the physical and chemical properties of the drilling fluid, including

a. density, [Ref: DR 60(3)(d)]
b. viscosity, [Ref: DR 60(3)(d)],
c. water loss, [Ref: DR 60(3)(d)],
d. filter cake, [Ref: DR 60(3)(d)]
e. salinity, pH, gel strengths, [Ref: DR 60(3)(d)]
f. solids content, [Ref: DR 60(3)(d)]
g. in the case of an oil base drilling fluid, the oil content of the fluid and the amount of base oil retained on cuttings, and
h. any other physical and chemical properties which have a bearing on the safety and effectiveness of the drilling fluid system.

3.11 Cementing System

3.11.1 The cementing system should consist of

a. bulk tanks and storage facilities with capacity to permit the onboard storage of adequate

   quantities of bulk cement and cementing fluid additives which may be necessary for the well program;

b. compressors, piping, surge tanks, and hoppers to permit the safe and effective transfer of all bulk cement and cementing fluid additives to the cement mixing equipment;
c. cement mixing equipment to ensure the safe, effective and controlled mixing of cement slurries;
d. sufficient equipment to ensure the appropriate dryness of air used in the transfer of bulk materials for the cementing system;
e. sufficient redundancy in the equipment and in the layout of equipment referred to in paragraph (b) to permit, with the plugging of any major line or the malfunction of any compressor, air receiver, or fluid additive equipment component, the safe transfer of bulk cement and cementing fluid additives to the cement mixing equipment; and
f. at least two cement pumps which should be manifolded together and which should
   i. have a pressure and volume rating to allow pumping of cement slurry at the maximum pressures and flow rates anticipated during any cementing operation;
   ii. be capable of accurately displacing slurries in a controlled manner;
   iii. be equipped so that personnel operating the system can monitor the flow rate, pump pressure and density of the cement being pumped, and
   iv. meet the requirements of subsection 3.7.1, if the pumps are also intended to fulfil the requirements for a high pressure kill pumping system.

3.12 Marine Riser System

3.12.1 The marine riser system on floating drilling installations should

a. be capable of withstanding the differential pressure of the drilling fluid relative to the sea; [Ref: DR 59(1)(c)]

b. be equipped and supported in a manner which effectively isolates the riser from the motion of the drilling installation; [Ref: DR 59(2)]
c. possess sufficient structural strength to withstand the maximum stresses to which it may be subjected; [Ref: DR 59(1)(c)] and
d. be equipped, where necessary, to prevent excessive vibrations due to waves or current.

3.12.2 Except as otherwise stipulated by these requirements, the marine riser system should be designed and constructed in accordance with

- American Petroleum Institute **Recommended Practice for Design and Operation of Marine Drilling Riser Systems**, API RP 2Q, Second Edition, April, 1984; and
- American Petroleum Institute **Recommended Practice for Design, Rating and Testing of Marine Drilling Riser Couplings**, API RP 2R, First Edition, May, 1984.

3.12.3 The marine riser system should be designed such that

a. the maximum stress intensity for all operating modes is not exceeded;
b. the maximum stress, fatigue resistance, deflection and column buckling are considered in the design; and
c. lateral deflection during normal drilling operations does not interfere with the passage of downhole tools.

3.12.4 The marine riser tensioning system should

a. be capable of maintaining the minimum allowable tension in all operational conditions; and
b. in the case of dynamically positioned vessels, be equipped to prevent damage of the marine riser system following disconnection of the lower marine riser package from the blowout preventer stack under high tension.

3.12.5 The telescopic joint should have a stroke of sufficient length to compensate for heave during all normal operations as well as all operations which may be undertaken prior to disconnect from the blowout preventer stack, and should, in every case, be greater than 45 feet (13.7 m).

3.12.6 An operating envelope should be established for the operation of the marine riser system which should include

a. limitations in terms of vessel offset or ball/flex joint angles, vessel motions, lateral deflection of the riser or any combination thereof, or any other limitation on the system, which, if exceeded, will necessitate suspending operations and disconnecting the marine riser from the blowout preventer stack;
b. the effects of various combinations of tension, mud density, water depth and environmental loads, or any combination thereof, and any other variable affecting riser

performance, and the optimum tension which should be used for the various factors affecting riser performance under various operating scenarios.

3.12.7 The operating envelope for the marine riser system described in 3.12.6 should be contained in the operating manual for the marine riser system or otherwise readily available to the persons responsible for the operation of the system.