

Managed Pressure Drilling Operations — Pressurized Mud Cap Drilling with a Subsea Blowout Preventer

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Foreword

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- the term “shall” denotes a minimum requirement to conform to the specification;
- the term “should” denotes a recommendation or that which is advised but not required to conform to the specification;
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Introduction

These guidelines (recommended practices)—prepared by the IADC Underbalanced Operations (UBO) and Managed Pressure Drilling Committee, and consisting of representatives from various IADC member companies—represent a composite of the practices employed by various operating companies, service companies, and drilling contractors in managed pressure drilling operations. In some cases, a reconciled composite of the various practices employed by these companies was used. This publication is under the jurisdiction of the American Petroleum Institute, Drilling and Production Operations Subcommittee.

Managed pressure drilling operations are being conducted with full regard for personnel safety, public safety, and preservation of the environment in such diverse conditions as urban sites, wilderness areas, ocean platforms, deep-water sites, very hot barren deserts, and cold-weather areas, including the Arctic environment and wildlife refuges. As tools and equipment continually improve and develop, the technology has been applied in many geologic formations, including oil and gas reservoirs and on sour wells, thus driving the need for globally accepted standards and safe operating best practices.

Managed Pressure Drilling Operations — Pressurized Mud Cap Drilling with a Subsea Blowout Preventer

1 Scope

This document addresses recommended practices for pressurized mud cap drilling (PMCD) from a floating rig with a subsea BOP stack. When massive lost circulation conditions are encountered, PMCD can be implemented to allow well construction operations to continue:

Although this document only addresses PMCD, most of the equipment described may also be used for the surface back-pressure (SBP) method of managed pressure drilling. However, much of the equipment used for SBP is not required for PMCD, and will not be covered here.

The following methods, described briefly, are also used during lost circulation conditions; however, they are outside the scope of this document:

- a) blind drilling (see 4.3.2);
- b) continuous annular injection drilling (see 4.3.3);
- c) floating mud cap drilling (see 4.3.4).

2 Normative References

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

API Standard 2RD, *Dynamic Risers for Floating Production Systems*

API Recommended Practice 16Q, *1st Edition, Recommended Practice for Design, Selection, Operation, and Maintenance of Marine Drilling Riser Systems*

3 Terms, Definitions, and Abbreviations

3.1 Terms and Definitions

For the purposes of this document, the following terms and definitions apply.

3.1.1

blind drilling

A method where fluid is pumped down the drill string with no returns up the annulus.

3.1.2

common well barrier element

Barrier element that is shared between the primary and secondary barrier envelopes.

3.1.3

continuous annular injection

A method where fluid is continuously pumped down the drill string and the annulus.

3.1.4

equivalent circulating density

ECD

Equivalent circulating density is the effective density of the circulating fluid in the wellbore resulting from the sum of the pressure imposed by the static fluid column, friction pressure, and surface back-pressure.

3.1.5**floating mud cap**

A method in which the hydrostatic pressure of a full column of annular fluid is higher than the sum of formation pressure and injection friction so that the fluid level remains below the surface.

3.1.6**formation integrity test****FIT****formation competency test**

Application of additional pressure by applying a surface pressure on a fluid column to determine the ability of a subsurface zone to withstand a planned pressure.

3.1.7**gas-free pressure**

The pressure in the annulus with a full column of mud and no gas above the loss zone.

3.1.8**gas migration pressure**

The pressure in the annulus after gas has migrated above the loss zone.

3.1.9**gunk**

A mixture of diesel oil and bentonite (and possibly cement).

NOTE Gunk pills can be used to form a downhole gelled fluid plug by mixing with a suitable water-based fluid that activates the gelation process downhole.

3.1.10**light annular mud****LAM**

The drilling fluid used in the annulus in pressurized mud cap drilling, the weight of which requires the use of an acceptable annular surface pressure.

3.1.11**leak-off test****LOT**

Application of a surface pressure on a fluid column to determine the pressure at which the exposed formation accepts drilling fluid.

3.1.12**managed pressure drilling****MPD**

An adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore.

3.1.13**pressurized mud cap drilling****PMCD**

A process in which the annulus is completely filled to surface with a fluid whose hydrostatic pressure is slightly lower than formation pressure and the resulting annulus shut-in surface pressure is the difference between formation pressure and the hydrostatic pressure of the annular fluid.

3.1.14**primary well barrier**

First well barrier that prevents flow from a source.

3.1.15**primary well barrier element**

The individual equipment items and components that form the primary barrier.

3.1.16**rotating control device****RCD**

Drill-through equipment designed to allow the rotation of the drill string and containment of pressure by the use of seals or packers that seal against the drill string (drill pipe, casing, etc.).

3.1.17**sacrificial drill string fluid****SAC**

The fluid pumped down the drill string and into the formation in pressurized mud cap drilling.

3.1.18**secondary well barrier**

Second well barrier that prevents flow from a source.

3.1.19**surface back-pressure****SBP**

A managed pressure drilling technique used to actively apply a pressure to obtain a target pressure at a selected point in the wellbore during all drilling operations (drilling, connections, tripping, etc.).

3.2 Abbreviations

For the purposes of this document, the following abbreviations apply.

AP	annular preventer
ATR	above tension ring
BHA	bottom-hole assembly
BHP	bottom-hole pressure
BLAT	BOP landing and assist tool
BOP	blowout preventer
BTR	below tension ring
DP	dynamic positioned
ECD	equivalent circulating density
FIT	formation integrity test
GFP	gas-free pressure
HPU	high-pressure unit
HSSE	health, safety, security, and environment
ID	inner diameter
LAM	light annular mud
LCM	lost circulation material
LMRP	lower marine riser package
LOT	leak-off test
LPR	lower pipe ram

LWD	logging while drilling
MPD	managed pressure drilling
MPR	middle pipe ram
MWD	measurement while drilling
NRV	non-return valve
OD	outer diameter
OEM	original equipment manufacturer
P&ID	process and instrumentation diagram
POOH	pull out of hole
PRV	pressure relief valve
PWD	pressure while drilling
RCD	rotating control device
RED	riser emergency disconnect
RGH	riser gas handling
SBP	surface back-pressure
SWL	safe working load
SWP	safe working pressure
UPR	upper pipe ram
UPS	uninterruptible power supply
WBE	well barrier element

4 Managed Pressure Drilling Overview

4.1 Managed Pressure Drilling Objectives

MPD is an adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore. The objectives are to ascertain the downhole pressure environment limits and to manage the annular hydraulic pressure profile accordingly. It is the intention of MPD to avoid continuous influx of formation fluids. Any influx incidental to the operation shall be safely contained using an appropriate process. The following are aspects of MPD operations.

- a) The MPD process employs a collection of tools and techniques that can mitigate the risks and costs associated with drilling wells that have narrow downhole environmental limits, by proactively managing the annular hydraulic pressure profile.
- b) MPD may include control of back-pressure, fluid density, fluid rheology, annular fluid level, circulating friction, and hole geometry, or combinations thereof.

4.2 Available Managed Pressure Drilling Solutions

MPD can be divided into the following categories depending on how the open-hole pressure is controlled and managed:

- a) annular friction—systems allowing for constant circulation during drill pipe connections, thereby using annular friction to maintain constant bottom-hole pressure;

- b) surface pressure—systems manipulating annular pressure at surface to control and manage downhole pressures;
- c) delta energy—systems where energy is added to manipulate the wellbore pressure by the use of equipment within the wellbore.
- d) hydrostatic pressure—systems creating a non-uniform hydrostatic profile;
- e) pressurized mud cap—systems used to drill without returns with an annulus fluid column assisted by surface pressure.

4.3 Mud Cap Drilling Methods

4.3.1 General

The term “mud cap drilling” is often used to describe drilling methods where there are no returns to surface. Sections 4.3.2 through 4.3.5 comprise a partial list of some of the more common methods that are sometimes referred to as mud cap drilling.

4.3.2 Blind Drilling

Blind drilling is a drilling method in which fluid is pumped down the drill string with no returns up the annulus. Little, if any, fluid is pumped down the annulus. It is called blind drilling because there is no way to reliably ascertain the precise downhole conditions unless or until returns come to surface.

EXAMPLE Drilling is continued after a total loss of returns. It is called “blind” because no effort is made to keep the annulus full or to maintain contact with or even monitor the fluid level in the annulus. This means there is no way to detect an influx from the formation until either gas migrates through the annular fluid and reaches the surface, or enough influx occurs to lighten the total annular column to the point that the well can flow to the surface. Blind drilling is primarily employed in situations where total losses make it impossible to circulate any fluid to the surface, and there are no productive formations exposed to the wellbore.

This method is not covered by this document.

4.3.3 Continuous Annular Injection

Continuous annular injection is a drilling method in which fluid is pumped down the drill string, as well as the annulus, continuously.

EXAMPLE Fluid is pumped down the drill string to clean and cool the bit and operate the motor, MWD, etc., and additional fluid is continually pumped down the annulus at a rate high enough to overcome formation fluid migration velocity up the hole and keep everything going into the formation. If the formation pressure and annular injection friction pressure combined are less than the hydrostatic pressure of the fluid being pumped down the annulus, there will be no annular pressure at the surface (floating mud cap). If the hydrostatic pressure of the annular fluid is less than the combination of formation pressure and annular injection friction pressure, there will be positive surface annular pressure (pressurized mud cap).

This method is not covered by this document.

4.3.4 Floating Mud Cap Drilling

Floating mud cap drilling is a method in which the hydrostatic pressure of a full column of annular fluid is higher than the sum of formation pressure and injection friction, so the fluid level remains below the surface or floats.

EXAMPLE With a subsea BOP stack, it is possible to monitor the fluid level in the riser with either a pressure sensor on the riser or by filling one of the choke or kill lines with a fluid that is light enough to maintain a column all the way to the surface and with some surface shut-in pressure. Using either of these pressure-monitoring techniques makes it possible to use the principles of PMCD. However, due to changes in wellbore geometry, applying PMCD methods with a fluid level that can rise and fall requires much more complex calculations than are required if there is a static fluid column all the way to the surface.

For example, a given volume of formation fluid that migrates (due to differences in density with the annular fluid) above the top fracture causes a significantly different reduction in the hydrostatic pressure at the top fracture than it does at the BOP stack. The differences can be calculated, but the calculations are more complicated than with a static fluid column.

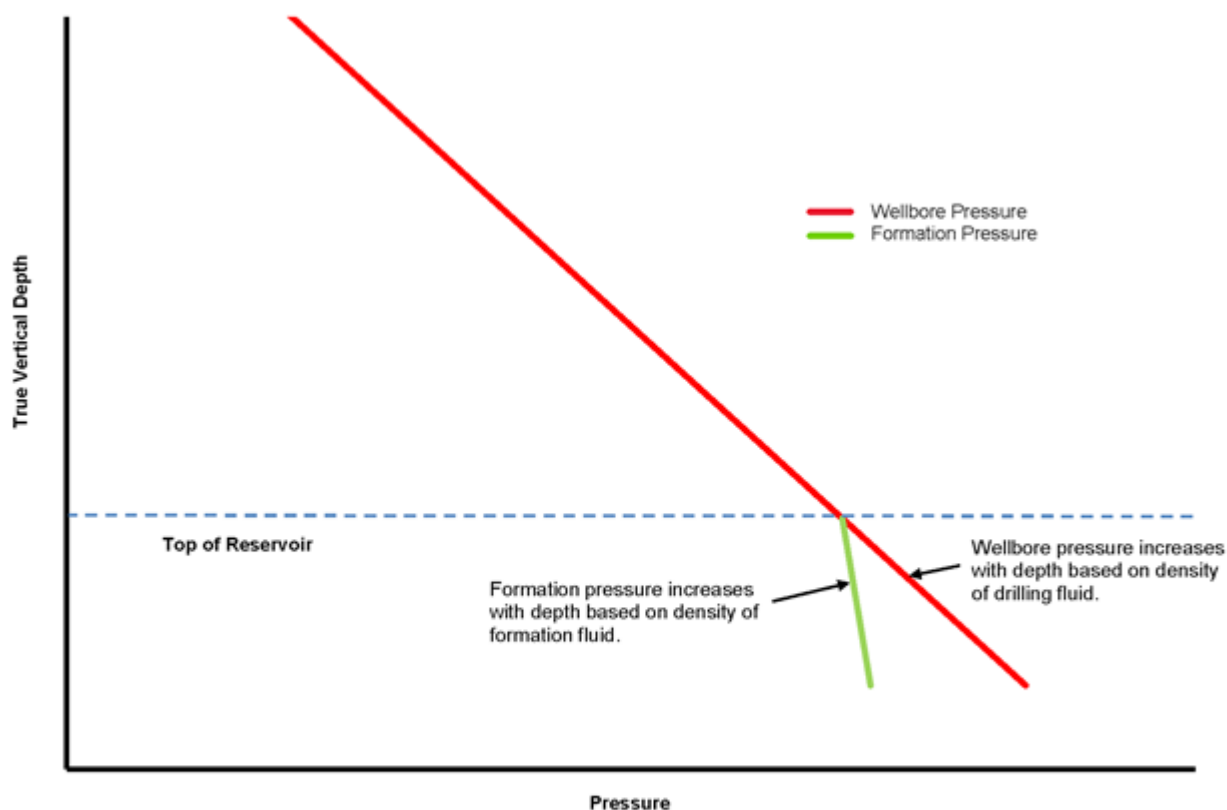
This method is not covered by this document.

4.3.5 Pressurized Mud Cap Drilling (PMCD)

Pressurized mud cap drilling is a drilling method in which the annulus is completely filled to the surface with a fluid whose hydrostatic pressure is slightly lower than formation pressure, and the resulting annulus shut-in surface pressure is the difference between formation pressure and the hydrostatic pressure of the annular fluid (see Figure 1 and Figure A.1 in Annex A).

EXAMPLE A sacrificial fluid, usually seawater, is pumped down the drill string to clean and cool the bit and to power the motor, MWD, etc. When the pumps are running, the annular pressure will increase by the friction pressure required to force fluid and cuttings into the formation. If any formation fluid migrates above the top fracture due to density differences, an increase in shut-in annular pressure will be detected, and enough additional annular fluid can be injected to force the formation fluid back into the formation.

This is the method addressed in this document. See Figure 2 for an example equipment schematic for pressurized mud cap drilling.



Assuming the mud weight exactly balances the formation pressure at the top of a reservoir, in all wells, a pressure imbalance exists between the well bore and formation and increases with depth.

Figure 1—Pressure Increases with Depth Based on the Density of the Fluid Contained

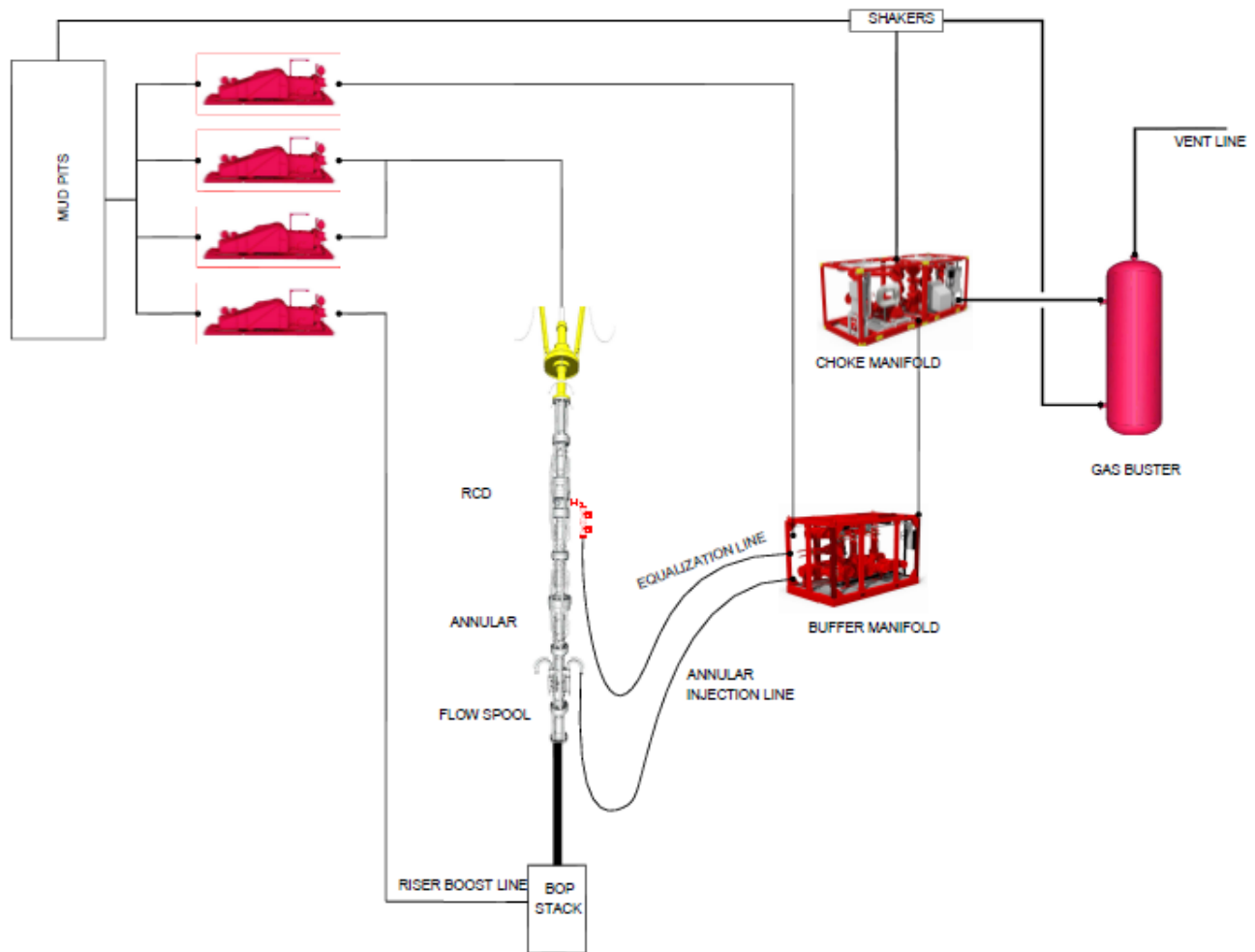


Figure 2—Example Equipment Schematic for PMCD with a Subsea BOP

5 Logistics

As with any operation, it is essential that logistic considerations be adequately addressed to make sure that all required materials are on hand and in sufficient quantities to ensure that operations are not interrupted. For PMCD operations, this means the sacrificial fluid, dry material for additional mud mixing (LAM), spares for the RCD and other expendables, etc., are available.

6 Equipment

6.1 Surface Equipment

6.1.1 Distribution/buffer manifold should be considered for the desired operational functionality if surface back-pressure (SBP) technique will be used. A distribution/buffer manifold enables the diversion of fluids into or out of the well.

6.1.2 Sacrificial fluid treatment upstream of the rig pump suction should be considered for minimizing corrosion.

6.1.3 Sufficient pump capacity to pump sacrificial fluid down the drill string and LAM in the annulus shall be available.

6.1.4 Sufficient delivery capacity to build and transfer either LAM or sacrificial fluid shall be available to meet or exceed the pump rate required to go downhole.

6.1.5 A choke to bleed off drill string pressure should be installed on the bleed-off line to reduce wear and tear on valves (see Figure 3). The location of the choke should allow for ease of access and operation. The returns should be routed to a measuring tank.

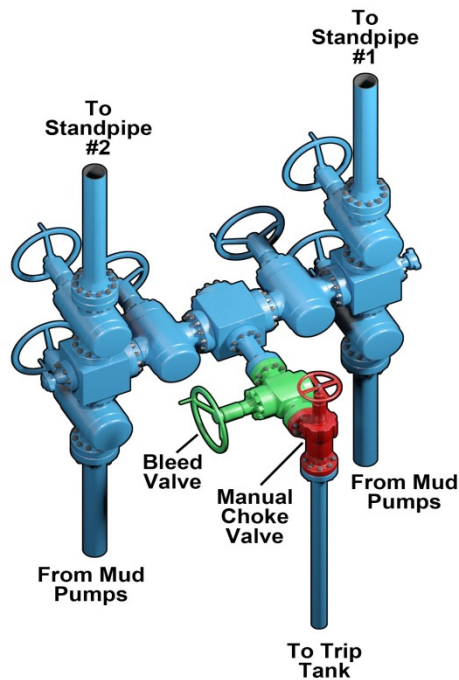


Figure 3—Example of Bleed-off System

6.2 Marine Equipment

The intention of this section is to describe and give guidance on equipment considerations and practices that should be considered when planning floater (subsea BOP) operations related to PMCD. The marine equipment may include the following:

- a) lower BOP stack assembly;
- b) lower marine riser package;
- c) marine riser;
- d) booster line;
- e) riser fill-up valve;
- f) termination joint;
- g) intermediate flex joint;
- h) rig telescopic joint assembly;
- i) flow spool or outlet(s) on rotating control device;
- j) MPD annular or alternative device;
- k) rotating control device;
- l) MPD telescopic joint;

- m) rig upper flex joint and diverter assembly;
- n) flexible hoses.

6.2.1 General Principles

6.2.1.1 It shall be possible to maintain the current well conditions while changing the RCD element.

6.2.1.2 A sealing device below the RCD (currently annular devices are used) should be considered for use in RCD element replacements.

6.2.1.3 An updated shut-down philosophy covering the MPD riser components shall be established for both planned and unplanned events.

6.2.1.4 The riser shall be protected from overpressure.

6.2.1.5 Riser pressure protection should be provided by PRV designed in accordance with the following standards:

- API 14C or ISO 10418;
- API 520;
- API 521;
- IEC 61511–1.

Riser loads shall be evaluated with respect to maximum surface pressure. MPD riser components should possess suitable tensile strength, pressure strength, and fatigue life for the operations planned, including riser deployment and recovery, ideally matching or exceeding the existing riser tube/connector strength, whichever is the lesser. Ideally, this arrangement should enable all MPD equipment to be installed in the riser string prior to BOP being latched to the subsea wellhead (refer to API 2RD).

Riser fatigue assessment should consider vortex-induced vibration and pressure cycling.

6.2.1.6 Flexible hoses and related fittings should be suitable for anticipated service conditions, harsh environments, currents, thruster forces, maximum anticipated operating pressures, potential collapse pressures, drilling fluids planned for use, and any wellbore fluids or gases that may pass through them when handling influxes. Applicable standards should be used during design. For example, API 17K, ISO 13628–10, API 17J, API 17B, ISO 13628–11, or fit-for-purpose testing can be used for qualification.

6.2.1.7 The system that controls the MPD components should be independent of the BOP control system.

6.2.1.8 Items to consider for equipment selection include, but are not limited to, the following.

- a) What additional equipment is needed and what rig systems can be used?
- b) What fluid types are required?
- c) Any environmental risks from fluid required or selected?
- d) Where are controls to be placed (e.g. driller's station, moonpool, emergency control room/safe refuge, etc.)?

6.2.2 RCD Selection Considerations

The following are several key operational considerations relating to these devices.

- a) Consideration should be given to API 16RCD regarding pressure ratings. The pressure rating is a manufacturing specification for design verification of the RCD only. Operability of the RCD should be determined with the RCD manufacturer.
- b) The tension rating of the RCD should be adequate for the application.
- c) At a minimum, the RCD sealing elements should be validated in accordance with API 16RCD. Additional testing is advisable for operations with drilling muds (OBM, SBM) that are outside the scope of API 16RCD. The RCD manufacturer should be consulted for test data.
- d) RCD seal elements are expendable items and their pressure capability can decrease with usage. Fit-for-purpose testing may be required to establish operating pressure values. Rig positioning, pipe movement due to heave, pipe condition, drilling fluid, flowing temperature, type of sealing element, etc., can further reduce pressure capability.
- e) A plan should be developed for running and retrieving the seal assembly and include the following:
 - change-out criteria;
 - wellbore isolation;
 - equipment handling and working platforms;
 - personnel roles and responsibilities;
 - mitigations for misalignment issues;
 - limits for heave and sea state;
 - determining if wear protection is required post retrieval;
 - effects of solids and cuttings in the fluid preventing installation or removal;
 - need for continuous circulation or not during the operation;
 - temporarily securing the well in case the need arises to pull the RCD housing back to the rig floor;
 - verifying RCD seal elements properly locked in place.
- f) Fluid compatibility between the element and all fluids that it will be exposed to should be verified in advance of operations.
- g) A suitable stock of spare elements should always be on hand and stored/handled in accordance with manufacturer's recommendations. Consideration should be given to having adequate parts and tools to facilitate efficient element change-out.
- h) Eccentric forces caused by pipe "wobble" and/or misalignment can lead to premature failure of the RCD unit. The distance between the rotary and the top element should also be considered. Pipe wobble can occur due to natural resonances of the drill string and can vary with rotational speed and pipe length above the RCD. During operations, this can be minimized by manipulation of rotary speed.
- i) Drill pipe design and condition, such as tong marks, hard banding, ID grooves, and tool joint upset angle, can influence element life and should be considered during the planning stages of an MPD operation.
- j) Source properly sized elements for all planned operations and contingencies.

- k) Full bore access through the RCD housing is necessary for certain operations, such as BOP testing and running a storm packer. The drift ID of the RCD housing shall be adequate to enable these operations.
- l) An RCD shall not be considered as a replacement for conventional well control equipment.
- m) Consideration should be given to multiple seal elements in the RCD, or alternative means to determine seal element wear.
- n) Gas bleed should be rigged below the RCD sealing element.
- o) If an ATR system is selected, consider the pressure rating limitation of the slip joint packer if this will be exposed to SBP.
- p) Pressure testing operations for the RCD shall be defined and include the marine riser burst limitations.
- q) A plan shall be in place to monitor for leakage past the RCD sealing element(s). For rig ups that do not include the riser above the RCD (to route leakage to the flow line), the plan shall include how the leakage will be recovered and how spills will be prevented.
- r) The procedure for running the riser and landing the BOP may require modification to include installation of the RCD, or a separate procedure may be used if the RCD is installed after latching the BOP.
- s) If MPD logging operations are to be conducted, the necessary RCD strippers or inserts must be available.
- t) The RCD failure modes (hydraulic, electrical, pneumatic) shall be identified and plans in place to prevent the situation from escalating due to a power failure.

6.2.3 Alternative Riser Isolation Device Considerations

The alternative riser isolation device (e.g. MPD annular), is a recommended component in the system used for PMCD operations. In addition to the items in 6.2.2, consider the following when selecting, installing, and using the device.

- a) Is it acceptable to pull the riser to change the elastomer?
- b) Is it acceptable to use one of the subsea annulars at the mudline?
- c) What is the existing functionality available at the rig; i.e. does the rig incorporate a riser gas handler (RGH)?

6.2.4 Riser Configurations

6.2.4.1 General

There are two main MPD riser component configurations, classed as follows.

- a) above tension ring (ATR): denotes that the MPD telescopic joint, RCD housing, MPD annular, and flow return spool (if used) are inserted in the riser string above the riser tensioner load ring.
- b) below tension ring (BTR): denotes that the RCD housing, MPD annular, and flow return spool are inserted in the riser string below the riser tensioner load ring.

There are other configurations used that involve alternative placement of the required equipment. The following subsections briefly describe some typical equipment layouts, listing points to be aware of during planning and design. These arrangements are discussed from the bottom up, starting from the subsea BOP stack assembly, which is latched to the subsea wellhead

6.2.4.2 Riser System Common Elements

6.2.4.2.1 Lower BOP Stack Assembly

The lower BOP stack assembly typically includes a wellhead connector, ram and annular BOP equipment, fail-safe choke and kill valves, choke and kill hard piping, and riser connector mandrel.

6.2.4.2.2 Lower Marine Riser Package

The lower marine riser package (LMRP) typically includes a riser connector, annular BOP equipment, fail-safe choke and kill valves, choke and kill hard piping and flexibles, booster line valves and hard piping, a lower flex joint, and riser adapter.

6.2.4.2.3 Marine Riser

The marine riser typically includes a c/w integral choke, kill, booster (dependent on rig class), and hydraulic lines (dependent on rig class).

6.2.4.2.4 Termination Joint

A termination joint may or may not be used depending on the rig class. It provides a means of interfacing choke, kill, booster, and hydraulic lines on the riser, with flexible hoses linking them to the rig's surface hard piping. Alternatively, these interfaces may be mounted directly to the rig telescopic joint outer barrel without a termination joint being used.

6.2.4.3 Above Tension Ring System Description

6.2.4.3.1 Intermediate Flex Joint

An intermediate flex joint may or may not be used depending on the rig class. It provides a means to allow for rig movement during extreme weather after LMRP is unlatched from the lower BOP stack. The capabilities (combined tension and internal pressure loading) of the intermediate flex joint can influence the location of the RCD due to its lower pressure rating.

6.2.4.3.2 Riser Fill-up Valve

Consideration should be given to removing the riser fill-up valve to minimize the potential for leakage.

6.2.4.3.3 Rig Telescopic Joint Assembly

The rig telescopic joint assembly potentially includes interfaces for choke, kill, booster (dependent on rig class), and hydraulic lines (dependent on rig class). For the ATR configuration, there are several alternatives for increasing the pressure-containing capacity with the rig telescopic joint exposed to the applied pressure, including the following.

- a) Collapse telescopic joint and lock the inner barrel, and energize both packers with maximum energizing pressure; dependent on packer supplier, this may allow surface applied pressures typically in the range of 750 psi to 1000 psi (5171 kPa to 6895 kPa), subject to OEM verification.
- b) Remove inner barrel and slip joint packer housing, and install crossover between slip joint outer barrel flange and a riser connector to enable handling as per a standard riser joint.
- c) Replace slip joint with a purpose-built riser tension crossover joint. Consider spillage mitigation.

Consideration should be given as how to get return flow to the surface if an RCD is not installed (i.e. multipart slip joint, flow lines, etc.).

6.2.4.3.4 Above Tension Ring MPD Riser Components

Above tension ring MPD riser components consist of the following.

- a) riser connector to mate with outer barrel or riser tension crossover;
- b) return flow outlets (e.g. flow spool) with hydraulically controlled MPD dual isolation valves, providing means to route well return fluids through suitable flexible hose(s) to the rig and provide a way to inject fluid into the top of the riser;
- c) a means for installing a suitably rated PRV to enable overpressure protection for the riser;
- d) MPD annular (or means of enabling an alternative barrier, such as the LMRP annular); this provides means of maintaining back-pressure while changing out the RCD seal element in the event of leakage;
- e) for dynamically positioned vessels, ability of the ATR MPD system to accommodate vessel heading change;
- f) RCD housing plus suitably rated flexible hose to enable bleeding off or equalizing pressure/checking for gas below the RCD seal element before changing it out above a closed MPD annular.

See Figure 4 for an example configuration of the MPD riser components in an ATR system.

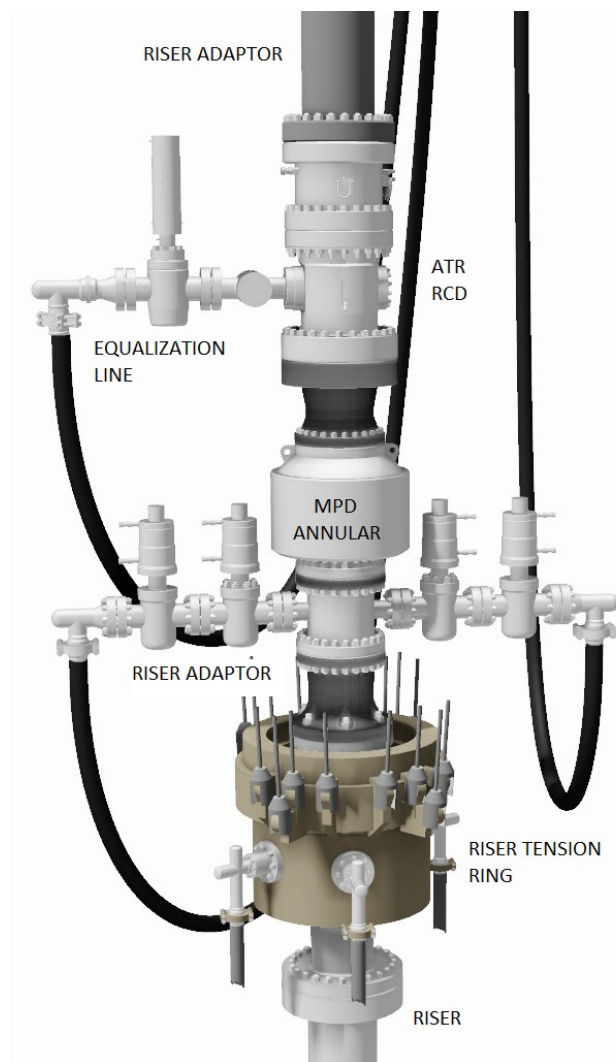


Figure 4—Example MPD ATR Riser Component Configuration