Managed Pressure Drilling Operations—Surface Back-pressure with a Subsea Blowout Preventer

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Introduction

These guidelines (recommended practices) prepared by the IADC Underbalanced Operations and Managed Pressure Drilling (UBO/MPD) Committee, 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 utilized. 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 diverse conditions such as urban sites, wilderness areas, ocean platforms, deep water sites, very hot barren deserts, 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 geological 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—Surface Back-pressure with a Subsea Blowout Preventer

1 Scope

1.1 General

This document provides information for planning, installation, testing, and operation of wells drilled with surface back-pressure (SBP) managed pressure drilling (MPD). This document applies only to drilling rigs with subsea blowout preventers (BOPs).

This document addresses situations where the total drilling operation is performed balanced or overbalanced, including both hydrostatically overbalanced (no supplemental surface pressure needed to control inflow) and hydrostatically underbalanced (supplemental surface pressure needed to control inflow) systems. See Annex A for guidance on planning and executing influx management using MPD techniques. For underbalanced operations, refer to API 92U.

1.2 Installation and Use of Blowout Preventers

Installation, testing, and use of BOPs and associated secondary well control equipment are similar to conventional drilling operations and are not included in this publication. This equipment should only be used during routine MPD operations (e.g., seal element changeout) if an adequate risk assessment has been performed. Refer to API 53 for information regarding installation and testing of BOPs in a conventional drilling operation.

2 Normative References

This document contains no normative references. For a list of documents associated with API 92S, see Bibliography.

3 Terms, Definitions, and Abbreviations

3.1 Terms and Definitions

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

3.1.1
anchor point
The depth in the wellbore that a constant annulus pressure is intended to be kept.

3.1.2
common well barrier element
Barrier element that is shared between the primary and secondary barrier envelopes.

3.1.3
distribution/buffer manifold
A manifold used to facilitate the distribution of fluids into and out of the well.

3.1.4
drilling window
Pressure range between the higher of pore/collapse pressure and fracture/fluid losses pressure.

3.1.5
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.

3.1.6
formation integrity test
FIT
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
hazard identification study
HAZID
The process of identifying hazards to plan for, avoid, or mitigate their impacts.

3.1.8
hazard and operability study
HAZOP
A structured and systematic examination of processes (existing or planned) to identify and evaluate problems that can represent risks to personnel, environment, or equipment or prevent efficient operations.

3.1.9
influx management envelope
IME
The safe operating limits when experiencing incidental influxes during MPD operations..

3.1.10
kick
An unplanned, unexpected influx of liquid or gas from the formation into the wellbore.

3.1.11
kick tolerance
Maximum influx volume at a specific intensity that can be safely circulated out of the well without compromising the weakest point (formation, casing, surface equipment, etc.).

3.1.12
nonreturn valve
NRV
A valve installed in the drill string that provides positive and instantaneous shutoff against flow or differential pressure from below.

NOTE Sometimes referred to as a float valve.

3.1.13
operator
The company having legal authority to drill wells and undertake the production of hydrocarbons.

3.1.14
primary well barrier
First well barrier that prevents flow from a source.

3.1.15
rotating control device
RCD
Drill through equipment designed to allow the rotation of the drill string and containment of pressure using seals or packers that seal against the drillstring (drill pipe, casing, etc.).

3.1.16
rotating control device (RCD) sealing element
Sealing element between the rotating control device and the drill string.

3.1.17
safe working load
SWL
Maximum load that the lifting equipment is certified to withstand under normal use.

3.1.18
secondary well barrier
Second well barrier that prevents flow from a source.

3.1.19
stripping
Adding or removing the drill string or coiled tubing drill string through a sealed control device.

3.1.20
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 drilling operations (drilling, connections, tripping, etc.).

3.1.21
well barrier
Envelope of one or several well barrier elements preventing fluids from flowing unintentionally from the formation into the wellbore, into another formation, or to the environment.

3.1.22
well barrier element
The individual equipment items and components that form the well barrier.

3.1.23
well control event
An event during well activity that requires activation of the BOP equipment when the operational envelope of the primary barrier is exceeded.

3.2 Abbreviations

ATR above tension ring

BHA bottom-hole assembly

BHCP bottom-hole circulating pressure

BHP bottom-hole pressure

BLAT BOP landing assist tool

BOP blowout preventer

BPP back-pressure pump

BTR below tension ring

CBHP constant bottom-hole pressure

CLPF choke line friction pressure

DP dynamically positioned

ECD	equivalent circulating density
FEED	front-end engineering design
FIT	formation integrity test
FMEA	failure mode and effects analysis
HAZID	hazard identification study
HAZOP	hazard and operability study
HPHT	high-pressure high-temperature
HPU	hydraulic power unit
HSE	health, safety, and environment
ID	inner diameter
IME	influx management envelope
LCM	lost circulation material
LMRP	lower marine riser package
LWD	logging while drilling
MAWP	maximum allowable working pressure
MGS	mud/gas separator
MPD	managed pressure drilling
MWD	measurement while drilling
NRV	nonreturn valve
OD	outer diameter
OEM	original equipment manufacturer
P&ID	piping and instrumentation diagram
PFD	process flow diagram
PRV	pressure relief valve
PWD	pressure while drilling
RCD	rotating control device
RED	riser emergency disconnect
RGH	riser gas handler
RIH	running-in-hole
SBP	surface back-pressure
SPP	standpipe pressure
SWL	safe working load
SWP	safe working pressure
UPS	uninterrupted power supply

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 be safely contained using an appropriate process. The following are aspects of MPD operations.

a) 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 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.

c) When compared to conventional overbalanced drilling, MPD can allow faster corrective action to deal with observed pressure variations. The ability to dynamically control annular pressures facilitates drilling of what might otherwise be technically unattainable prospects.

NOTE SBP techniques include, but are not limited to, keeping the borehole completely filled with drilling fluid of the proper weight or density during operations, exercising reasonable care when tripping pipe out of the hole to prevent swabbing and keeping track of the amount of drilling fluid put into the hole to replace the volume of pipe removed from the hole during a trip.

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 (CBHP);

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 nonuniform hydrostatic profile;

e) pressurized mud cap—systems used to drill without returns with an annulus fluid column assisted by surface pressure.

4.3 Candidate Selection Criteria

4.3.1 Applications

A basic analysis may be considered to determine if MPD is applicable and which technique should be used. The following scenarios are good examples to consider for MPD application:

a) narrow drilling windows;

b) formations prone to wellbore instability due to pressure cycles;

c) wellbore ballooning (breathing);

d) formations prone to lost circulation;

e) high-pressure high-temperature (HPHT) wells;

f) formation pressure uncertainty;

g) early kick detection and response;

h) high-pressure/low-productivity formation, rate of penetration improvement.

4.3.2 Selection Considerations

4.3.2.1 Technique Selection

For each well, there are various techniques (under/overbalanced fluid, single/two-phase flow, early kick detection, etc.), equipment, and specifications that can provide a solution. The first analysis that should be performed is the selection of the MPD technique that is going to be used, taking into account the advantages and disadvantages of each approach.

4.3.2.2 Regulations

Regulations and regulatory approvals should be reviewed and investigated as some restrictions can apply.

4.3.2.3 Rig

Rig equipment specifications (pump rates, subsea equipment pressure and structural limits, fluid/material compatibility, pit volumes, etc.) should be reviewed and investigated. Circulation system flexibility should be reviewed for normal and contingency operations. Schematics or proposed schematics of all MPD equipment (process and instrumentation diagram [P&ID], including footprints, line sizing, valves, pressure ratings, and other design considerations including rig interfaces, weight, handling considerations, etc.) shall be available. Equipment redundancy will be dictated by the safety, reliability, and flexibility requirements.

4.3.3 Geology

The MPD design should take into account the uncertainties of the geology, for example, formation depths, drilling window (pore pressure range, fracture and collapse pressures), presence of fractures, weathered or karstified formations, as these uncertainties can lead to different scenarios and affect the MPD operation (pump pressure, SBP, anchor point determination, etc.).

Understanding the uncertainties in the comprehensive geological and geophysical model and drilling window is key for a well-constructed MPD design.

4.3.4 Casing and Completion Design

The casing and completion design should consider the impacts of the MPD operations, including load cases imposed by MPD operations, as these can differ from conventional drilling load cases.

Consideration should be given to the following:

— deployment scenario (liner, casing, liner plus tie-back, in casing isolation valve, lower completion);

— isolation strategies (cementing operations, usage of mechanical barriers, packers).

4.4 Managed Pressure Drilling Components

This document considers the following as typical components of MPD systems. These systems include, but are not limited to, the following:

a) the rig circulating equipment;

b) the drill string;

c) drill string nonreturn valves (NRVs);

d) BOP equipment;

e) marine riser and additional components;

f) pressure control devices (rotating and nonrotating) independent of the conventional rig BOP (e.g., rotating control device [RCD], MPD annular);

g) choke-, kill-, and booster-lines;

h) MPD flow lines;

i) distribution/buffer manifold;

j) choke manifolds;

k) MPD mud/gas separator (MGS) equipment (as required);

l) control systems;

m) pressure, volume flow, mass flow, etc. sensors;

n) hazardous gas sensors (H_2S, etc.);

o) rig personnel safety and warning devices and signs;

p) MPD back-pressure pump (BPP) or rig pump diverter system;

q) continuous circulation equipment.

4.5 Well Barriers

During SBP MPD, the primary well barrier can be different from that of conventional drilling operations. The secondary well barrier remains the same for MPD operations as for conventional drilling operations. For additional details refer to Section 8.

5 Planning

5.1 General

The purpose of this section is to outline the planning and review practices that should be conducted to ensure the safety and integrity of MPD projects.

5.2 Technical Feasibility

The objective of a technical feasibility study is to determine if MPD is suitable technology.

The analysis should be conducted addressing (but not limited to) the following.

a) Identifying qualified potential service providers.

b) Conducting preliminary well design, including consideration of the following:

   1) drilling concerns, including the rationale for using MPD;

   2) operational window, based on pressure prognosis (fracture, formation, and collapse pressures), geological hazards, and pressure uncertainties;

   3) H_2S considerations;

   4) calculations and response for kick/loss tolerance;

   5) review barriers/safety margins during well operations (e.g., drilling, stripping, displacement, tripping, completions, riser disconnect, etc.);

   6) casing design;

   7) tubing and completion design;

   8) directional plan for the well;

   9) drill string/bottom-hole assembly (BHA) configuration;

   10) selection of drilling fluid type, weight, and rheology;

   11) hydraulics modeling and sensitivity analysis for all operations;

   12) rig type and rig class requirements;

   13) rig and riser modification requirements;

   14) water depth;

   15) metocean data, potential impact on downhole pressure variations;

   16) proposed schematics (draft P&ID) of MPD equipment, including footprints, line sizing, valving, pressure rating, and other design considerations including rig interfaces, weight, etc.;

   17) SBP range;

   18) geomechanical study;

   19) dispensations from regulations needed;

   20) transition between MPD operations and conventional operations;

   21) tripping considerations.

5.3 Front-end Engineering Design

The purpose of this section is to describe and give guidance for the front-end engineering design (FEED) that should be conducted based on the feasibility study. The FEED should include, but not be limited to, the following.

a) Well design.

1) Pressure prognosis plots through the interval showing the available drilling window.

2) Ambient, circulating, and static temperature profiles.

3) Hydrate formation potential.

4) Geological technical data examining the risks of abnormalities or geological uncertainties, and the probabilities of larger differences in pore pressure and fracture pressures.

5) Casing design.

6) Tubing and completion design.

7) A description of all drilling concerns.

8) Hydraulics modeling.

9) Pipe light considerations.

10) Transition between MPD operations and conventional operations.

b) Equipment.

1) Rig and rig equipment selection:

— circulating system capability (rates/pressure);

— condition of drill pipe;

— preliminary riser analysis;

— riser gas handling;

— detailed rig and riser modification requirements and interfaces.

2) MPD equipment and/or service provider selection:

— detailed schematics, such as P&ID and process flow diagram (PFD) of all MPD equipment, including footprints, line sizing, valving, and design considerations;

— layout, zoning modification, and rig interfaces (electrical, air, water, etc.);

— equipment specifications and pressure ratings of MPD equipment.

3) Specifications of MPD equipment redundancies including emergency shutdown philosophy.

4) Specifications of MPD control systems.

5) Offsite and precommissioning testing requirements.

6) Tie-in to rig's circulation system and assess any impact on the current system. Perform the utility tie-in and interface with the existing utility systems. Evaluate the deck layout and MPD handling/lifting plan. Plan any needed tie-in/interface with the rig's existing control system.

c) Safety and regulatory requirements.

1) Identification of project hazards by hazard identification (HAZID) study, including the development of mitigation measures and contingencies.

2) Identification of any needed dispensations from regulations.

3) Classification society requirements.

4) Pressure relief valve (PRV) philosophy.

d) Procedures outline.

1) A description of the kick/loss detection methods.

2) Procedures and contingency plans for MPD operations.

3) A bridging document agreed to by the operator and rig contractor addressing MPD operations that do not comply with either company's well control manual or operational procedures.

e) Training and competency.

1) A training program and objectives for key personnel.

2) A method of competency assurance.

5.4 Safety Studies and Reviews

Given that MPD can result in a different pressure profile in the well compared to conventional operations, a HAZID study (or equivalent initial risk assessment technique) should be performed to identify wellbore system risks that are not normally present. Hazard and operability (HAZOP) studies (or equivalent detailed risk assessment technique, failure mode and effects analysis [FMEA], cause and effect, etc.) should also be performed as a safety and operability review. The purpose of the HAZOP is to critically review the proposed plan to identify and correct, or develop, contingency plans for potential problems. The HAZOP study should be conducted as part of the detailed design, with sufficient time allowed prior to the start of operations for all action items to be closed out. Reference documents should include the drilling program, equipment specifications and layout, P&ID and/or PFD, procedures, and other industry guidelines.

The IADC UBO/MPD HSE Guidelines [41] provide details on conducting HAZID, HAZOP, and other safety studies for MPD operations.

5.5 Emergency Response Plan

An emergency response plan incorporating MPD considerations should be developed for the operation.

5.6 Detailed Design Engineering

The detailed design of an MPD operation and the development of a basis of design should address the following issues.

a) Current pressure prognosis plots with pore pressures, stability pressures, and fracture pressures through the interval showing the available drilling window.

b) Geological technical data examining the risks of abnormalities or geological uncertainties in pore pressure and fracture pressures and reservoir technical data, including target formation lithology, height, porosity, permeability, fluid type.

c) Casing design calculations with safety factors.

d) Schematics of MPD equipment, including footprints, line sizing, valving, and design considerations (P&ID or PFD).

e) Surface circulation system design specifications and redundancies, specifically for MPD implementation.

f) Rig and riser modification requirement including classification documentation.

g) Detailed riser analysis (including pressure limitations).

h) Detailed analysis of the MPD system for riser gas handling.

i) Data system integration requirements.

j) Detailed MPD control system design.

k) Onshore testing requirements.

l) Field or site requirements to install and operationally test the MPD equipment in a benign environment.

m) A detailed well monitoring plan for detecting variations in flow rate in and out including the following:

    1) trip tank and pit system procedures;

    2) mud return flow trending;

    3) the use of flow meters;

    4) choke response;

    5) logging tools;

    6) measurement while drilling (MWD);

    7) pressure while drilling (PWD) and logging while drilling (LWD);

    8) gas detection equipment installed;

    9) mud sampling procedures;

    10) rheology monitoring;

11) alarm philosophy.

n) Development and review of operational, contingency, and well control procedures.

o) Detailed training plan.

p) A description of drilling and reservoir concerns, including the rationale for using nonconventional drilling technology.

q) Hydraulics modeling plans using a range of anticipated fluid properties, well geometries, drill sting configurations, and drilling parameters.

r) H_2S consideration including surface monitoring and alarms; mud additives/scavenger and monitoring; exposure of riser.

s) Identification of all project hazards and the development of mitigation measures and contingencies.

t) All relevant submissions to and approvals from regulatory authorities.

As with any operation, it is essential that logistics be addressed to make sure that required materials are on hand and in sufficient quantities to ensure that operations are not interrupted. For MPD operations this means that additional fluid volume requirement and dry material for additional mud mixing, spares for the RCD and other expendables, etc. are available.

6 Equipment

6.1 Surface Equipment

6.1.1 Surface Equipment Components

The following surface equipment considerations are provided. The final system configuration will be dependent on local requirements and the available operational drilling window. MPD systems may include the following equipment—the list is neither prescriptive nor exhaustive:

a) MPD choke manifold;

b) pressure relief system;

c) bypass valves;

d) PRV discharge tank;

e) pipework and hoses;

f) isolation valves;

g) MGS;

h) flow metering (both in and out);

i) rig pump encoders;

j) gas meter;

k) local spill containment;

l) distribution/buffer manifold;

m) BPP;

n) rig pump diverter;

o) junk catcher;

p) continuous circulating equipment;

q) MPD-specific handling and testing equipment:

— winches,

— running tool for RCD bearing, and

— workshop containers.

6.1.2 Formation Protection Pressure Relief System

6.1.2.1 A suitable relief system should be installed to prevent over-pressurization and still maintain the required wellbore pressure.

6.1.2.2 The discharge piping design should consider the following:

a) area classification;

b) vertical displacements;

c) potential for line plugging;

d) volume measurement;

e) relief line reaction forces and restraint;

f) relief device sizing;

g) intervention procedures;

h) fluid stream composition including potential of hydrocarbons and control;

i) maintenance provisions.

6.1.2.3 Remote indication of activation/status is recommended.

6.1.3 Pressure Relief Valve at Equipment Specification Break

Installation of a PRV at a specification break between high- and low-pressure rated equipment is common in MPD systems to protect the lower-pressure rated equipment. Depending on the installation, a number of PRVs might be required. The PRVs should be designed in accordance with the following standards as applicable:

a) API 14C or ISO 10418;

b) API 520;

c) API 521;

d) IEC 61511-1.

6.1.4 Pressure Relief Discharge Tank

Placement of a separate pressure relief discharge tank might be necessary to discharge into a safe area. The sizing and level control/indication of this tank is important. Venting and overpressure protection of the downstream tank shall be evaluated, and adequate provisions provided. Consideration should be given to the possibility of potential hydrocarbons discharge from pressure relief system. Provision to empty this tank into the rig circulation system is also required.

6.1.5 Pressure Relief Lines

Routing of pressure relief lines should be reviewed to reduce the risk of obstructions in lines that can prevent PRVs from operating properly. Alternatively, lines may be flushed with clean fluid or air. Sizing of lines should be in accordance with API 520, Part I. The lines should be open-ended where possible with no valves. If valves are in lines they should be locked open during operations.

6.1.6 Managed Pressure Drilling Choke Manifold

MPD choke manifolds may be arranged in different configurations; consideration should be given to the specific needs of the operation as follows.

a) Flow rates—properly sized manifold as it relates to pressure drop across the equipment, erosion, plugging, etc.

b) Pressure—components should be rated for the drilling operation.

c) Redundancy—multiple flow paths.

d) Pressure control actuation—hydraulic, electric, pneumatic, manual, automation, remote operation.

e) Instrumentation—consideration should be given for measurement of flow rate and density, pressure, temperature, choke position, etc.

f) Means of confirmation of zero pressure.

g) Orientation/location and size of manifold—proximity to wellhead, hazardous area classification, minimize piping bends, service access.

h) Well effluent—drilling fluid, solids, formation influx, methane, H_2S, CO_2.

i) Failure modes.

j) Contingencies and mitigations.

k) Maintenance and repair.

l) Means to bleed off and drain the system.

m) Choke trim sizing to minimize/prevent plugging.

The MPD choke manifold is used for primary pressure control. Subsection 9.4 should be used to define the transition point between MPD and well control.

6.1.7 Junk Catcher

Consideration should be given to installing a junk catcher upstream of the MPD manifold. If a junk catcher is run, consideration should be given to the following:

— pressure monitoring across the junk catcher to determine plugging,

— effect of increase friction on SBP, and

— bypass and bleed-off facilities.

The ability to clean and change out the junk catcher screen(s) should be considered.

6.1.8 Flow Meter

6.1.8.1 Fluid composition, especially gas percentage, and flow rate can affect flow meter performance.

6.1.8.2 The size and pressure rating of the flow meter should be considered.

6.1.8.3 A valved bypass facility in case of blockage and for maintenance of the flow meter should be considered.

6.1.8.4 A mechanism to create pressure down-stream of the flow meter should be evaluated to ensure consistency and accuracy in the flow meter, especially if this is a Coriolis-type meter. Cavitation, siphoning, and particle sagging should be considered when installing the flow meter.

6.1.9 Pipework and Hoses

6.1.9.1 Pipework design should be fit-for-service and optimized to minimize back-pressure, erosion, and potential for solids to accumulate. Use of full-bore type valves should be evaluated to reduce the risk of solids buildup and valves plugging.

6.1.9.2 Consideration should be given for drain/flushing points.

6.1.9.3 All pipework and hoses shall be secured.

6.1.9.4 Various types of connections are available (hub, flange, union). Special consideration should be given to prevent Figure 1502 and Figure 602 and other union mismatches (see API 7HU1).

6.1.9.5 Fluid compatibility and temperature ratings of hose linings should be considered for operational use.

6.1.9.6 Consideration should be given to the transport, storage, and handling of hoses to prevent damage.

6.1.9.7 Temporary pipework design, manufacture, certification/traceability, connection type, installation, and restraints upstream of the MPD manifold should meet recommendations numerated in Section 6 of API 92U, First Edition, and other industry recommended practices.

6.1.9.8 The interconnecting pipework should be in accordance with applicable classification society requirements and industry-recognized standards, including consideration of fluid composition.

6.1.10 Back-pressure Pump

6.1.10.1 The choice of BPP type, if used, is important as it may have to be used either intermittently or continuously during MPD operations.

6.1.10.2 Temperature buildup should also be a consideration especially in oil-based muds where cross wellhead circulation can be required for extended periods of time.

6.1.10.3 The pump's power supply needs consideration, and where critical, stand-alone power supply should be provided.

6.1.10.4 Either fixed or variable speed pump types may be considered because they can offer various levels of accuracy of pressure control.

6.1.10.5 Fluid compatibility tests on rubber components should be carried out in advance of operations.

6.1.10.6 The use of a redundant rig or cement pump as an alternative or as a backup to a dedicated BPP may be an option.

6.1.10.7 Maintenance access issues should be considered in the design and placement of this unit.

6.1.10.8 Hazardous area classification should be considered in the design and placement of the pump.

6.1.10.9 The pump suction should be positively flooded. Strainers and junk catchers should be evaluated for installation upstream of the BPP.

6.1.10.10 In certain instances an in-line check valve(s) may need to be fitted to the BPP discharge line.

6.1.10.11 A pulsation dampener should be installed at the pump outlet for steady flow conditions.

6.1.11 Rig Pump Diverter

A flow-switching manifold may be used to provide SBP while making connections as an alternative to a BPP.

6.1.12 Continuous Circulating Equipment

On MPD operations where very tight operational windows are expected, some form of continuous circulation (continuous circulating devices, circulating subs, or coiled tubing) can be considered when planning MPD with SBP.

6.1.13 Flow Rate Instrumentation

Determination of flow-in and flow-out can be critical to the requirements of the MPD method employed on the operation. Considerations should be given to the method of measurement to ensure adequate accuracy and reliability. MPD flow-in measuring instrumentation can be independent from rig's flow-in measuring instrumentation. System should be calibrated against the system used to measure the rate being pumped into the well.

6.1.14 Mud/Gas Separator

6.1.14.1 A dedicated MPD MGS should be installed where the rig degasser is determined to be insufficient.

6.1.14.2 It can be advantageous to connect the MPD choke to the rig choke system; this provides flexibility in directing return flow to either the rig MGS or the dedicated MPD MGS from either choke manifold.

6.1.14.3 The following apply to the design of the MGS.

a) Design of the separator system (including both upstream and downstream piping diameter, run lengths, and number of turns) should be properly engineered to accommodate appropriate returns during operations.

b) The size of influx and intensity to be handled should be considered before reverting to well control equipment, as defined by the MPD operations matrix.

c) Confirmation shall be attained that the MGS capacity is not exceeded during influx circulation in accordance with the MPD operations matrix.

d) Any influx resulting from a dynamic pore pressure test should be considered during planning to ensure that the rig degasser or MGS can handle safely.

e) Suitable safety systems to enable management of pressure and fluid levels should be considered.

f) Mitigating flash back risk should be evaluated when using nonpressurized degassers.

g) The inlet to the MPD MGS from the MPD system should have a means of isolating the inlet flow and diverting to a safe area in the event the MGS flow capacity is exceeded.

6.1.15 Automated Control Systems

If an automated control system is used, the following should be considered.

a) Some automated SBP control systems rely on hydraulic modeling. The hydraulic model should be calibrated and verified prior to deployment. In addition, a calibration method should be in place to update the hydraulic model, as needed, during the planned operation. Fluid rheological properties should be measured in calibrated equipment and updated at regular intervals to reflect their impact in the resulting bottom-hole pressure (BHP), or when annular fluid properties and/or densities have been changed.

b) Care should be taken when changing from one pressure control set point location to another (e.g., bottom-hole conditions to surface conditions) to ensure the proper sequences are applied to the control set point change.

c) Ensure there is sufficient backup to any critical control system to secure the well in the event of any failure.

d) The control system should be designed according to industry-recognized standards.

e) All MPD control system failure scenarios identified in the MPD system FMEA should be simulated along with system response and appropriate corrective actions. The findings from this exercise should be incorporated in the well-specific MPD procedures.

6.1.16 Distribution/Buffer Manifold

A distribution/buffer manifold may be needed to facilitate the distribution of fluids into and out of the well.

The distribution/buffer manifold valves, as shown in Figure 1, should be designed according to API 6A, PSL 3 (or higher), with material Class DD, EE, FF, or HH. Piping shall be designed in accordance with applicable classification society requirements and industry-recognized standards, including consideration of fluid composition.

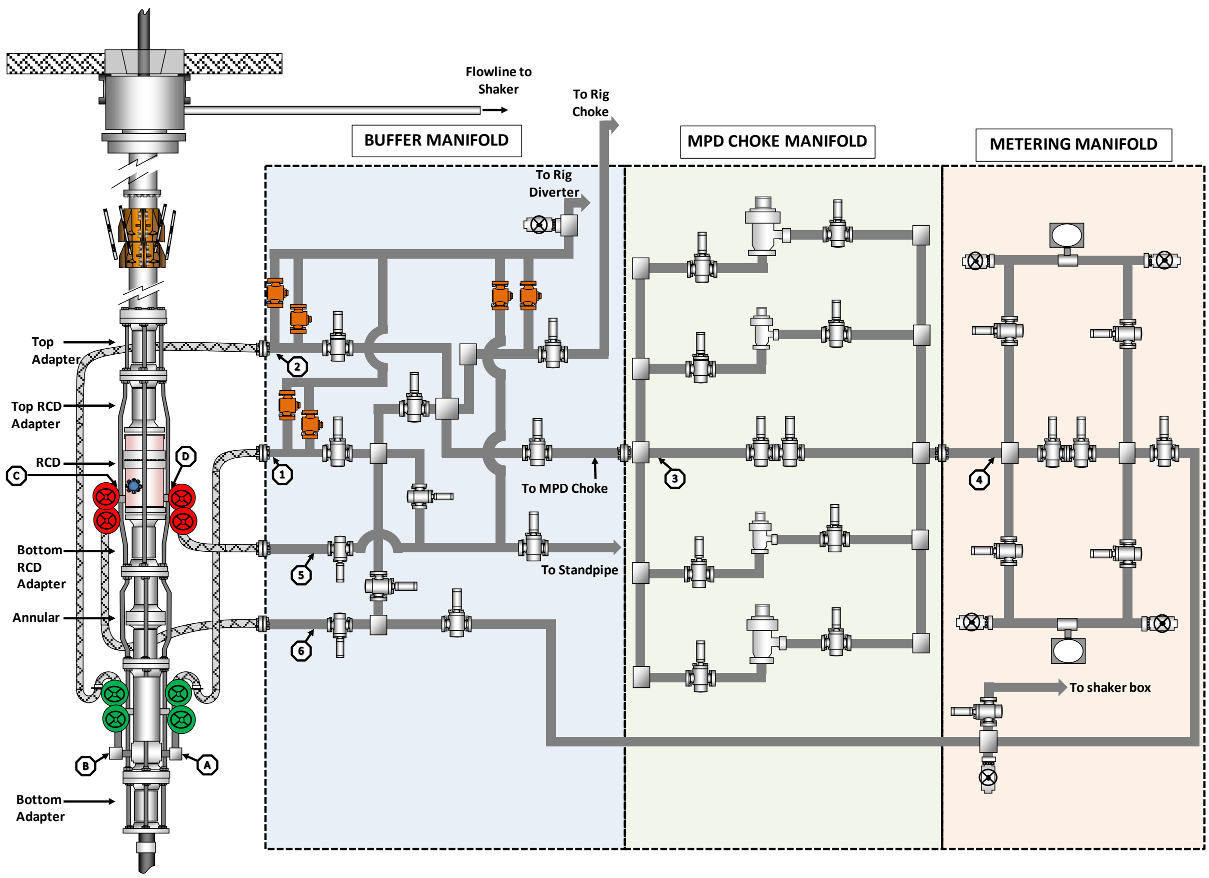


Figure 1—Simplified Managed Pressure Drilling P&ID Diagram

6.2 Marine Equipment

6.2.1 General

This section describes and gives guidance on equipment and practices that should be considered when planning floater (subsea BOP) operations related to MPD with SBP. The marine equipment may include the following:

a) lower BOP stack assembly;

b) lower marine riser package (LMRP);

c) marine riser;

d) booster line;

e) riser fill-up valve (should be isolated);

f) termination joint;

g) intermediate flex joint;

h) rig telescopic joint assembly;

i) flow spool or outlet(s);

j) MPD annular;

k) MPD telescopic joint (telescopic joint modified for MPD operations);

l) rig upper flex joint and diverter assembly;

m) flexible MPD return line(s);

n) RCD;

o) cross-overs to riser joints;

p) umbilicals.

6.2.2 General Principles

6.2.2.1 The primary well barrier shall be maintained while changing the RCD sealing element.

6.2.2.2 A device below the RCD (currently annular devices are used) should be considered.

6.2.2.3 The riser shall be protected from overpressure.

6.2.2.4 The maximum SBP on the marine riser equipment depends on the following.

a) A riser analysis considering the following:

- water depth,
- mud weight,
- riser tension, and
- riser and MPD components tensile capacities (combined load of applied tension and pressure).

b) The maximum SBP in combination with the above should not exceed the requirements of the API 16Q (the stress should not exceed 2/3 the riser yield strength).

6.2.2.5 Riser pressure protection provided by PRV designed in accordance with the following standards:

- API 14C or ISO 10418;
- API 520 (all parts);

— API 521;

— IEC 61511-1.

6.2.2.6 Riser loads shall be evaluated with respect to maximum surface pressure. MPD riser components shall possess suitable tensile and pressure strength, fatigue 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 the BOP being latched to the subsea wellhead (refer to API 2RD).

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

6.2.2.7 Flexible hoses and related fittings should be suitable for anticipated wear and service conditions; harsh environment, currents, thruster forces, maximum anticipated operating pressures, potential collapse pressures, drilling fluids planned for use and any wellbore fluids or gases that can pass through them when handling influxes. Applicable API documents should be used during design. For example, API 17K (ISO 13628-10), API 7K, API 17J, API 17B (ISO 13628-11) or fit-for-purpose testing can be used for qualification.

6.2.2.8 Vessel-induced dynamic motions should be considered for MPD equipment design and installation.

6.2.2.9 The system that controls the MPD components should be independent of the BOP control system. A risk assessment should be performed to determine if the BOP system capacity is adequate for controlling both systems and provides adequate additional pressure and volume for BOP activation in emergency situations. A failure of the MPD control system shall not compromise the operation of the BOP control system. Items to consider for equipment selection include the following.

a) What additional equipment is required and what rig systems can be used?

b) What fluid types are required?

c) Potential environmental risks from fluid required or selected.

d) Where are controls to be placed (drillers station, moonpool, emergency control room, safe refuge, etc.)?

6.2.3 Rotating Control Device or Similar Devices

The following apply to rotating control and similar devices.

a) Consideration should be given to the API 16RCD specification 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) As 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 necessary 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;

— when 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 is also a consideration. 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 may be minimized by manipulation of rotary speed.

i) Drill pipe design and condition such as tong marks, hard banding, inner diameter (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) RCD shall not be used as 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 above tension ring (ATR) system is selected, consider the pressure rating limitation of the slip joint packer if it 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 a riser above the RCD (to route leakage to the flow line), the plan shall include how the leakage will be recovered and spills 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 shall be available.

t) The RCD failure modes shall be known and plans in place to prevent the situation from escalating.

6.2.4 Alternative Riser Isolation Device Considerations

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

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)?

6.2.5 Riser Configurations

6.2.5.1 General

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

— 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;

— 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 that is latched to the subsea wellhead.

6.2.5.2 Riser System Common Elements

6.2.5.2.1 Lower Blowout Preventer Stack Assembly

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

6.2.5.2.2 Lower Marine Riser Package

The LMRP typically includes a riser connector, annular BOP equipment, failsafe choke and kill valves, choke and kill hard piping and flexibles, booster line valves and hard piping, lower flex joint, and riser adapter.

6.2.5.2.3 Marine Riser

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

6.2.5.2.4 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 riser with flexible hoses linking them to the rigs surface rigid piping. Alternatively, these interfaces can be mounted directly to the rig telescopic joint outer barrel without a termination joint being used.

6.2.5.3 Above Tension Ring System Description

6.2.5.3.1 Intermediate Flex Joint

An intermediate flex joint may or may not be used depending on the rig class. The capabilities of the intermediate flex joint influence the decision to use an ATR solution in preference to a BTR solution due to its pressure rating.

6.2.5.3.2 Riser Fill-up Valve

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

6.2.5.3.3 Rig Telescopic Joint Assembly

The rig telescopic joint assembly can potentially interface with choke, kill, booster (dependent on rig class), and hydraulic (dependent on rig class) lines. A full description of the complete arrangement (prior to modification for ATR operations) is given in 6.2.5.4. For the ATR configuration, there are several alternatives for increasing the pressure-containing capacity with the rigs telescopic joint exposed to the applied pressure including the following.

a) Collapse telescopic joint and lock the inner barrel, 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 verification by the original equipment manufacturer (OEM).

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 surface if RCD not installed (i.e., multipart slip joint, flow lines, etc.).

6.2.5.3.4 Above Tension Ring Managed Pressure Drilling Riser Components

ATR 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 also providing 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 BOP (or an alternative barrier such as the LMRP annular) that provide a means of maintaining SBP while changing out the RCD seal element in the event of leakage;

e) RCD housing plus suitably rated flexible hose to enable bleeding off or equalizing pressure and checking for gas below RCD seal element before changing it out above a closed MPD annular;

f) rig upper flex joint and diverter assembly.

For DP vessels, the ATR MPD system should accommodate vessel heading change.

See Figure 2 for an example of an ATR system.

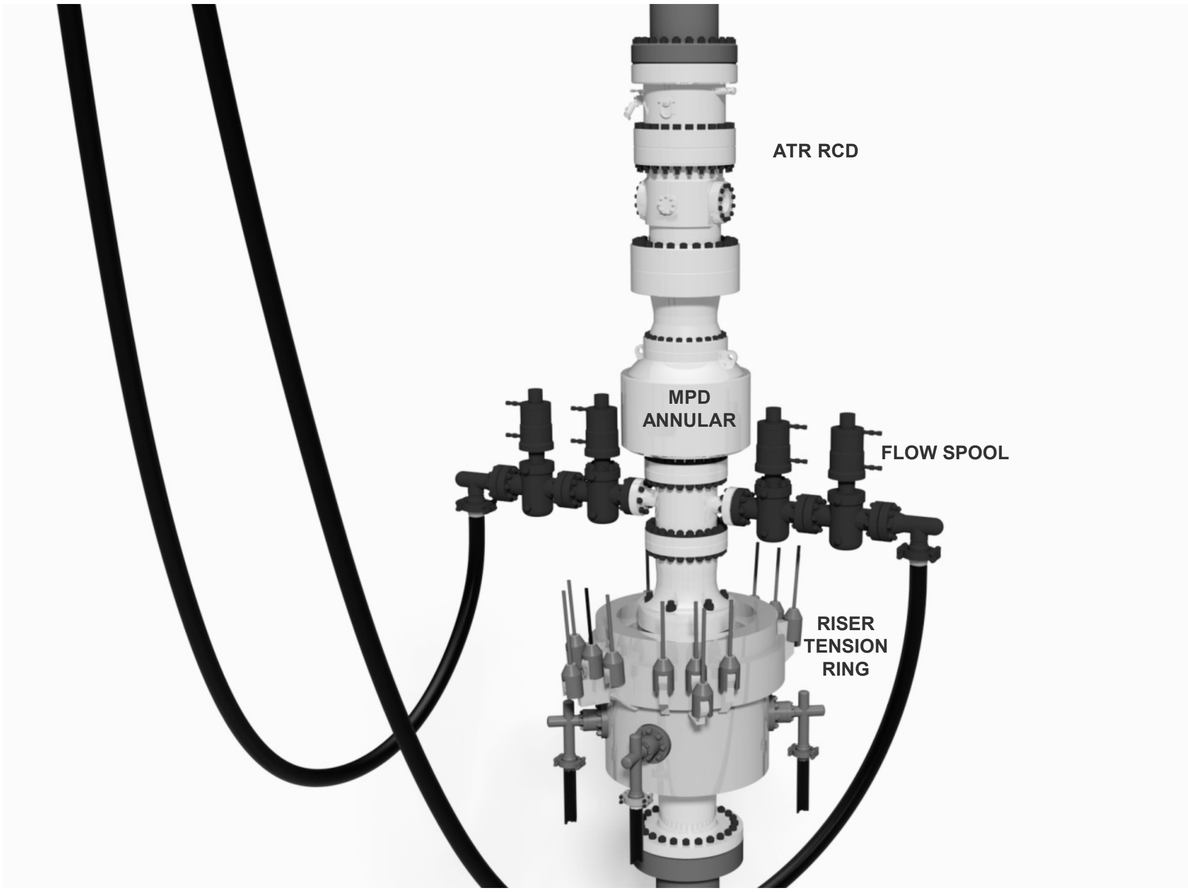


Figure 2—Above Tension Ring System Example

6.2.5.3.5 Above Tension Ring Design Considerations

6.2.5.3.5.1 The riser components above the RCD shall have an ID large enough to accommodate running the bearing assembly or any expendable that has to be changed while the RCD is in the riser.

6.2.5.3.5.2 Identify if the rig utilizes a BOP landing assist tool (BLAT), which latches into a profile in the riser string below the riser tensioner ring. Possible locations are as follows:

a) swage at bottom of telescopic joint outer barrel,

b) separate riser pup joint run below the telescopic joint, or

c) within the termination joint.

In the case of an ATR solution, IDs within the RCD housing or flow spool can prevent the BLAT tool being run and latched in position. The loss of this functionality should be reviewed, and alternative solution(s) identified.

6.2.5.3.5.3 The ATR solution brings other challenges to be addressed as follows:

a) reduced available telescopic joint stroke will introduce new operating limits (heave, DP);

b) space-out to accommodate MPD ATR riser components can involve extending tensioner wirelines that can create storage issues in moonpool, clashes when nippling up down LMRP/BOP from riser, and requirement to purchase new wirelines;

c) requirement to carry out a riser recoil analysis for the new riser configuration and limits with subsequent adjustments to riser recoil systems, potentially involving software and hardware changes.

6.2.5.3.5.4 Evaluate requirement to extend rig choke, kill, booster, and hydraulic hoses, resulting from rig telescopic joint outer barrel being set deeper than for standard drilling operations. If this is necessary, an evaluation of method should be done (addition of short extensions with appropriate connections). Evaluate whether replacement with new hoses made to length is required to mitigate potential leakage at intermediate connections.

6.2.5.3.5.5 Riser space-out should take into consideration tool joint placement during connections and depth correction positioning (i.e., tool joint at rotary).

6.2.5.4 Below Tension Ring System

6.2.5.4.1 Below Tension Ring System Description

6.2.5.4.1.1 The following describe a BTR MPD system:

a) a riser connector to mate with top of marine riser or termination joint (dependent on rig configuration);

b) a flow spool with hydraulically controlled MPD dual isolation valves that provides a means to route well return fluids through suitable flexible hose(s) to the rig and also provides 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) an MPD annular (or means of enabling an alternative barrier such as the LMRP annular); this provides means of maintaining back-pressure while changing out RCD seal element in the event of leakage;

e) an RCD housing, plus a suitably rated flexible hose, to enable bleeding off or equalizing pressure/checking for gas below RCD seal element before changing it out above a closed MPD annular.

See Figure 3 for an example of a BTR system.

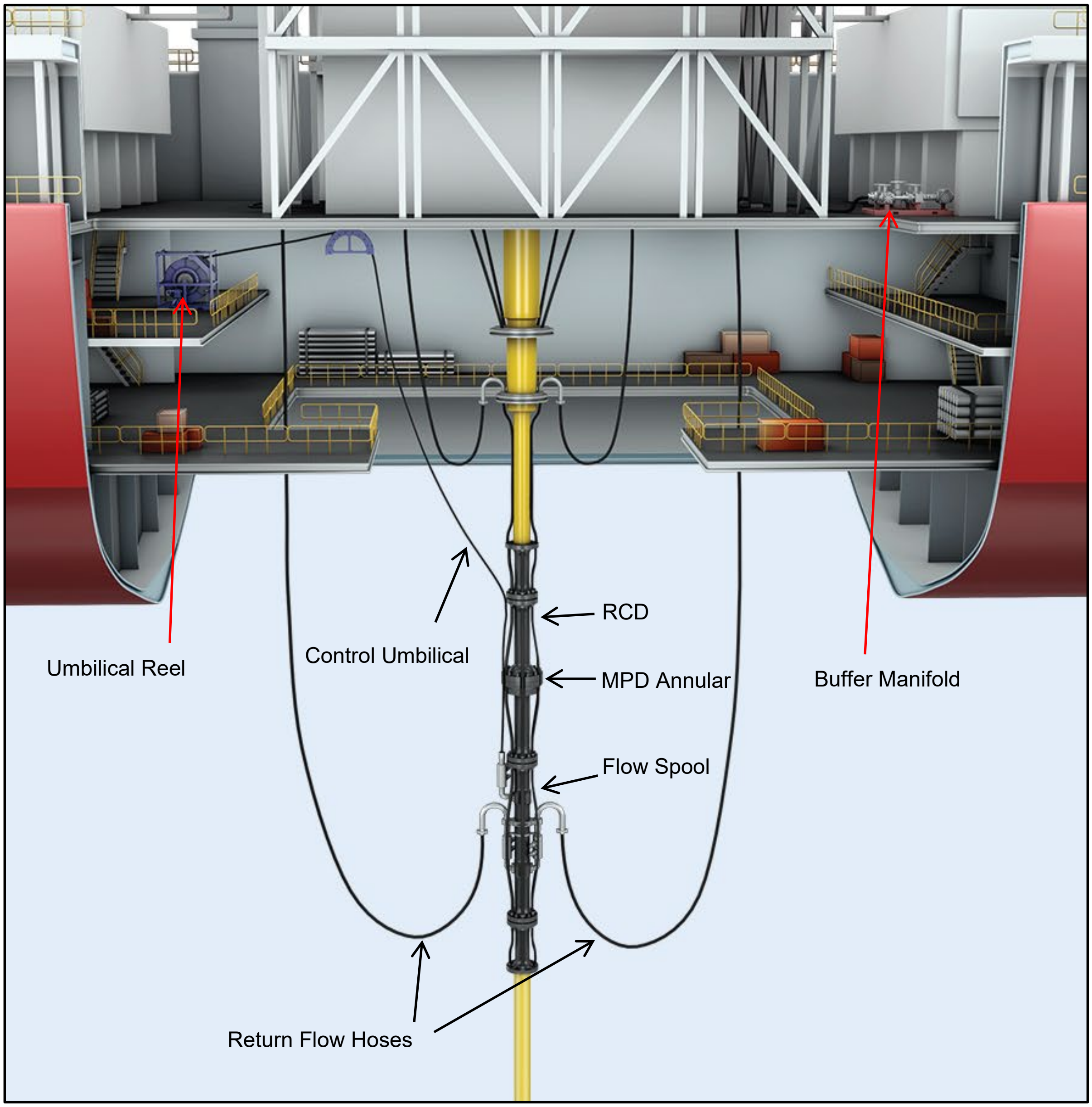


Figure 3—Example of Below Tension Ring Installation

6.2.5.4.1.2 An intermediate flex joint is optional.

6.2.5.4.1.3 The telescopic joint assembly may interface with choke, kill, and booster (dependent on the rig class) and hydraulic lines (dependent on the rig class). The complete assembly can include the following.

a) A riser connector that mates with top of riser space-out pup joint or rig upper flex joint and diverter assembly (dependent on rig configuration).

b) An outer barrel that includes a load ring that engages with the rigs riser tensioner ring.

c) A riser tensioner ring that provides a means for riser tensioners to apply the required top tension to the riser string and to compensate for rig motions. Depending on rig class and configuration, this can include fluid load-bearing utilized to allow a DP rig to "weathervane," integral remotely controlled connections for choke, kill, booster (dependent on rig class), and hydraulic (dependent on rig class) hoses.

d) A slip joint dual packer housing that provides the means to seal between outer and inner barrels when inner barrel is stroking to compensate for rig motions. Packers are typically energized utilizing rig air or hydraulic pressure. These are considered the riser internal pressure "weak link" with an industry-accepted safe working pressure (SWP) of 500 psi (3447 kPa).

e) A slip joint locking assembly that provides a means to lock inner and outer slip joint barrels together during BOP installation on and removal from the subsea wellhead. This assembly can be hydraulic remotely operated or manual (dependent on rig class).

f) An inner barrel with riser connector that mates with bottom of riser space-out pup joint or rig upper flex joint and diverter assembly (dependent on rig configuration).

6.2.5.4.1.4 A riser space-out pup joint may be used, dependent on whether the rig is fitted with in-line direct acting hydraulic tensioners or wireline tensioners.

6.2.5.4.2 Below Tension Ring Design Considerations

6.2.5.4.2.1 If an intermediate flex joint is required, and its pressure and tension combined loading capability is not adequate, a BTR solution is preferable.

6.2.5.4.2.2 Consider removing riser fill-up valve to minimize potential for leakage.

6.2.5.4.2.3 The riser components above the RCD shall have an ID large enough to accommodate running the bearing assembly or anything needed to be run while the RCD is in the riser.

6.2.5.4.2.4 Identify if the rig utilizes BLAT that latches into a profile in the riser string below the riser tensioner ring; possible locations are as follows.

a) Swage at bottom of telescopic joint outer barrel.

b) Separate riser pup joint run below the telescopic joint.

c) Within the termination joint. In the case of a BTR solution, the following challenges are addressed.

— BLAT profile located at bottom of telescopic joint outer barrel can have an ID less than that of the planned RCD stripper and bearing assembly.

— IDs within the RCD housing or flow spool can prevent the BLAT tool being run and latched in position (profile located below BTR MPD riser components).

The loss of this BLAT functionality should be reviewed, and alternative solution(s) identified.

The need to extend rig choke, kill, booster, and hydraulic hoses, resulting from insertion of BTR riser components above riser termination joint, should be evaluated. Consideration should be given to the addition of short extensions with appropriate connections or replacement with new hoses made to the length required to mitigate potential leakage at intermediate connections.

6.2.6 Riser Analysis and Riser Preparation

6.2.6.1 Riser inspection and operating records shall be reviewed, and, if deemed necessary, riser inspections shall be performed in accordance with the OEM's, drilling contractor's, or operator's procedures. If wear is detected in the riser main tube, it shall be eliminated if possible. If unable to eliminate ware, the resultant riser wall thickness shall be used in riser analysis calculations. All sealing areas shall be in serviceable condition, and repairs shall be made as required.

6.2.6.2 All riser equipment located above the RCD housing shall be drift tested.

6.2.6.3 A riser analysis shall be performed in accordance with API 16Q and API 2RD for the planned MPD well location considering the following:

a) planned maximum mud weight to be used;

b) maximum MPD SBP;

c) location metocean data;

d) including additional weight and location of MPD riser components (ATR or BTR);

e) surface conductor configuration;

f) wellhead configuration, BOP-LMRP configuration, subsea and upper flex joint configuration;

g) rig positioning; moored or DP;

h) drag effect from waves/currents on MPD riser components in splash zone.

6.2.6.4 The riser analysis report should include the following information for use by the rig operating crew:

a) API riser buckling stability criteria calculations in accordance with API 16Q and API 2RD;

b) global riser stress (Hoop and Von Mises) and fatigue analysis (see API 16Q, and API 2RD) for combined load case of maximum mud weight, environmental loads, SBP, and pressure cycling;

c) riser operability and drilling performance;

d) wellhead and conductor bending loads;

e) station-keeping watch circle limit guidance based on riser mechanical limitations.

6.2.6.5 A riser recoil analysis should include the following:

a) reduced available MPD telescopic joint stroke (ATR solution)—reduced distance to dissipate recoil energy after unlatching;

b) additional weights of MPD riser components above the tension ring;

c) potential impact loads on MPD riser components after closure of MPD telescopic joint;

d) effect of riser pressure in the recoil analysis;

e) changes to rig riser recoil software, hardware, or both to safely manage the revised riser arrangement.

6.2.6.6 Evaluate risk of riser and BOP-LMRP being affected by external differential (collapse) pressures; review riser, BOP, and wellhead connector limitations; review lower flex joint external pressure limitations.

6.2.6.7 Consider effect of emergency disconnect on the wellbore pressure (e.g., riser margin).

6.2.6.8 An example of output from the analysis is shown in Figure 4.

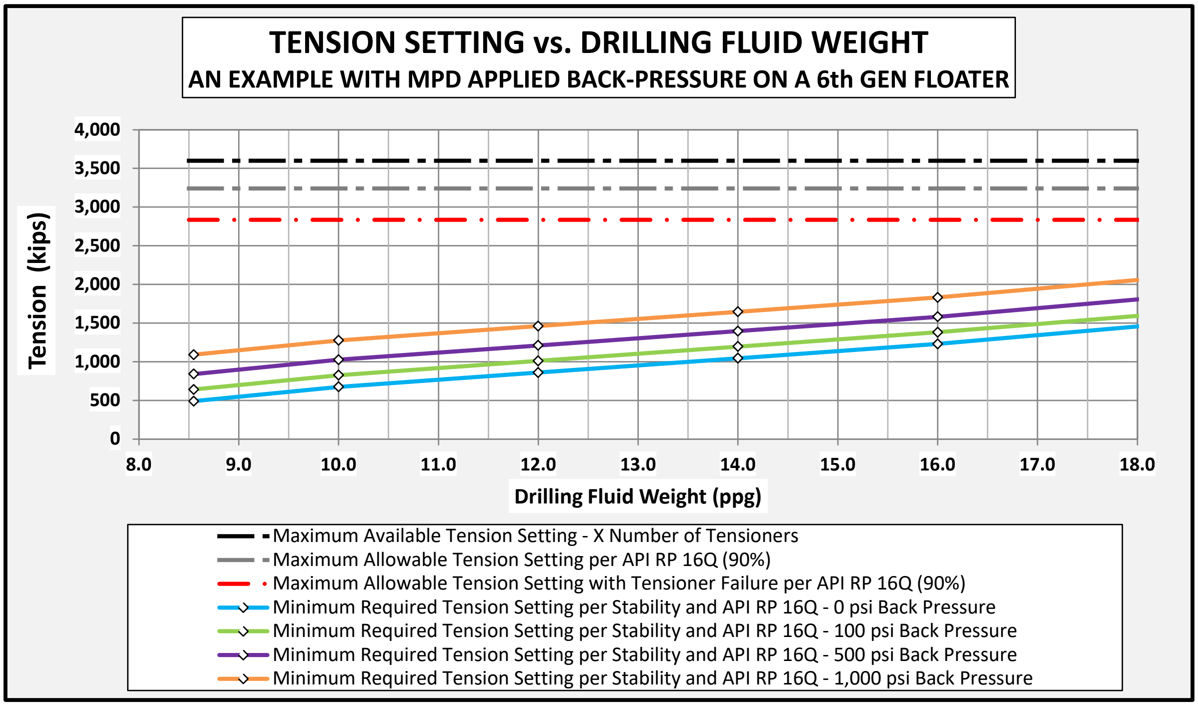


Figure 4—Example of Buckling Load Analysis Showing Interrelationship between Mud Weight and Tension Setting

6.2.7 Equipment Installation and Handling Considerations

6.2.7.1 Planning of Managed Pressure Drilling Operations

The following apply for planning MPD operations.

a) All riser components above the RCD shall have the appropriate internal diameter.

b) PRV philosophy should consider the well, the riser, gas handling, surface piping, and equipment.

c) MPD riser equipment should be designed so that it can be picked up, run, pulled, laid down like any other piece of rig riser equipment.

d) MPD riser component terminations can have the same riser flanges as the target rig riser string, which enables handling with rig's existing riser handling tools. If this is not the case, appropriate crossovers and adapters are required. Specialized handling tools shall be available to address on-site handling and service issues.

e) MPD riser component configuration and equipment should be designed to minimize over water and manriding operations during rig-up and rig-down, minimizing time spent on the critical path to hook up valves and flexible hoses.

f) The rigs handling equipment capacities should be verified for handling the MPD components. The pipe handling catwalk load capacity shall be sufficient for running the MPD riser components. If MPD riser components are larger or heavier than the rigs slip joint, the equipment may need to be handled in alternative manner.

g) The following points should be considered when developing the equipment installation and moonpool management plan.

— Do all winches planned for the operation have sufficient wireline to reach sea level whilst maintaining a safe amount of line on the winch drum?

— What means of communication are available to ensure safe and effective coordination of these activities between sea level, moonpool, and drill floor and the driller's doghouse?

— What is required to manage control umbilicals to—telescopic joint, RCD Housing, MPD annular and flow spool valves, hoses, securing same against weather and sea conditions?

— What is required to deploy and recover these control umbilicals safely and effectively? Should powered reels be used or not? Are there means to support umbilical turn-down sheave(s), suitable deckhead padeyes, suitable dropped object prevention, secondary retention points, and suitable locations to install additional padeyes, if required?

— What deck space is available around the moonpool and immediately adjacent area to accommodate equipment such as MPD hydraulic power unit (HPU) and control panel(s), umbilical reel(s), MPD flow hoses support goosenecks and surface lines?

— Can equipment be sufficiently secured to handle potential loadings due to operations, environmental forces, etc.?

— Are temporary walkways/gratings/handrails, etc. required to mitigate against slip/trip hazards?

— Between wells, during rig moves, etc., can the hoses and umbilicals be left rigged up and secured such that they are not damaged, creating additional drag during move, etc.

— Considerations for hose and umbilical management include hose length, termination point, reel placement, rig movement (rotational or heave loop), sequence of running umbilicals/lines/hoses, etc.

— For a DP vessel, consider the orientation of the gooseneck stabs to have hoses and umbilical lines terminate at one position on the rig (i.e., fore or aft).

6.2.7.2 Equipment Installation and Handling Considerations (Above Tension Ring)

The following points should be considered.

a) ATR operations should be considered only for extremely benign or calm sea conditions with little to no heave.

b) The ability to activate riser tensioners, land and latch BOP and layout handling/landing joint.

c) In the case of using an RCD that requires external and/or manual clamping and lubrication, the available air gap above sea level shall accommodate the MPD riser components such that the RCD clamp and lubricating points are accessible above sea level.

d) Manual moonpool operations should be minimal.

e) Method to install MPD riser components on top of the riser.

— Are ODs of MPD riser components less than rotary table/diverter housing/tension ring IDs? If not, then plans should include how to pick up the (“keel-haul”) equipment into place beneath the rotary table.

— Is the MPD multibarrel telescopic joint load-bearing?

— Is the drill string motion compensator able to handle light loads? This is important when landing MPD assembly with heave.

— Are there convenient work supports (riser tensioner ring?) for personnel involved in releasing and making up this connection (riser flange, quick latch)?

— Should use of remote hydraulically operated connector(s) (e.g., H-4 or HC Type) be considered to avoid personnel having to make up and release manual connections? What implications does this have for MPD riser components height and weight?

f) What manriding/work basket facilities are available on the rig?

g) What restrictions are in place regarding over-side and manriding work?

h) What utility winches are available both in the moonpool area or potentially deployed through the riser spider/rotary table from the drill floor?

i) What are the safe working load (SWL) capacities of the planned utility winches?

j) Can flow spool valves and MPD hoses be installed on to the MPD riser components before it is landed, avoiding difficulties associated with rig motion?

k) Can these hoses be oriented and protected to utilize spaces between riser tensioners (wire or direct acting piston rods)?

l) For DP vessels, considerations should be given for hoses and umbilicals orientation so as not to interfere with rig rotation.

6.2.7.3 Equipment Installation and Handling Considerations (Below Tension Ring)

The following points should be considered.

a) What manriding/work basket facilities are available on the rig?

b) What restrictions are in place regarding over-side and manriding work?

c) Location environmental considerations; likely sea states, weather patterns, etc.

d) Can MPD flow hoses be oriented to clear existing rig choke, kill, booster, and hydraulic hoses, allowing DP rigs to weathervane as normal without additional restrictions being imposed?

e) What utility winches are available both in the moonpool area or potentially deployed through the riser spider/rotary table from the drill floor?

f) What are the SWL capacities of the planned utility winches?

g) What are the increased loads as a result of extending choke, kill, booster, and hydraulic hoses where required by insertion of BTR MPD riser components above rig termination joint (if applicable)?

h) For DP vessels, considerations should be given for hoses and umbilicals orientation so as not to interfere with rig rotation.

6.2.7.4 Deck Handling Considerations

The following points should be considered.

a) How is existing rig riser equipment stored and handled (horizontal or vertical storage)?

b) Available deck space and deck loading capacity to accommodate the BTR MPD riser components and related shipping frame.

c) Deck crane capacities and applicable operating radii to enable equipment to be loaded on to the rig, prepared, and then moved to drill floor.

d) Restrictions associated with deck crane riser handling spreader beams and handling yokes; SWL, length ranges, etc.

e) The SWL and equipment length limitations for riser catwalks, riser catwalk handling machines.

6.2.8 Operating Considerations

6.2.8.1 Points to consider regarding overpressure protection of well bore, riser, and surface equipment include the following:

a) Control of MPD riser isolation valves:

- consequence of control systems failure (valves fail as is, fail open, fail closed);
- consequence of valve lineup changes for different MPD operations (SBP, PCMD, etc.);
- flow capacity;

b) Identification of “weak link” for various operations (e.g., well bore strength at casing shoe, riser limitations, RCD limitations, surface equipment limitations).

6.2.8.2 Considerations for dynamic positioning emergency operations are as follows.

a) What are the effects and limitations of selected MPD riser components in relation to

- loss of power and rig black-out mitigations,
- loss of positioning,
- riser emergency disconnect (RED) process, and

— RED process when there is gas in the riser.

b) Well control; agreed decision point to change over from primary well barrier to secondary well barrier utilizing the rig BOP and well control manifold equipment (reference MPD operations matrix).

6.3 Control Systems

6.3.1 The guidelines specified for the MPD choke manifold in 6.1.6 apply.

6.3.2 There shall be a control system for operating the RCD and any additional valves on the riser. If an annular is run just below the RCD on top of the riser, provision shall be made for its operation. Design of these systems should include consideration for redundancy and at least some limited operability in case of a power failure. Consideration should also be given to overpressure protection, failure position for valves and other equipment, i.e., fail open, fail closed, or fail as is. The connection for the controls is typically via an umbilical bundle containing the hydraulic, electric, pneumatic, etc. lines for the controls and sensors. When designing the system, careful consideration should be given to how this control umbilical will be deployed, connected, secured, retrieved, and stored when not in use, taking into account the other lines and equipment in the moonpool area.

6.3.3 Appropriate valve interlocks should be considered.

6.3.4 A redundant system, to monitor annular pressure shall be in place. As a safety precaution, any single failure should not lead to loss of annular monitoring system.

6.3.5 Control system monitoring capabilities, alarms, and responses to various scenarios should address the well, the riser, and the MPD surface equipment.

6.4 Rig Modifications

Certain rig modifications may be necessary to accommodate the MPD system prior to installation and operations. The extent of these will be system and site specific and will be controlled in accordance with the rig owner's policies and procedures.

The following are some considerations for MPD-related modifications.

a) Fluid feed from mud pits to BPPs/rig pump diverter:

— strainers;

— pressure gauges;

— pumped or gravity fed.

b) Return fluid downstream of the MPD choke:

— line size;

— routings;

— elevations;

— drainage points.

c) Modifications to riser systems:

— modifications to upper riser system;

— flowline to MPD manifold;

— pressure relief system;

— drainage;

— RCD integration.

d) Interface/integration with rig control systems:

— hardware and software testing;

— data acquisition integration;

— security;

— remote access;

— protocols;

— inputs and outputs.

e) PRV discharges:

— hydrocarbon content;

— safe area;

— monitoring/alarms.

f) Additional utility stations, electrical supply, and data cabling:

— fire and gas safety systems;

— H_2S monitoring and alarm system;

— uninterrupted power supply (UPS);

— emergency power assignment;

— communications;

— ergonomics;

— BPP power.

g) Installation of RCD assembly:

— RCD assembly may include flow spool, annular BOP, RCD, flow lines, etc.;

— height restrictions, correct space-out and position of RCD;

— contingency space-out for element removal in the case of stuck drill string;

— handling considerations;

— environmental containment system;

— installation and maintenance access;

— flowline orientation;

— equalization/vent line.

h) Rig circulating system:

— high pressure—rotary hose and standpipe pressure limitations;

— low pressure—the ability to maintain more than one mud system may be required;

— ensuring that existing rig equipment is reviewed for suitability;

— MGS limitations (total flow, gas flow, mud flow);

— flare/vent system adequacy/modifications;

— temporary piping tie down/restraints;

— actuated valves rig-up/location;

— requirement for access to trip tanks.

A choke to bleed off drillstring pressure may be installed on the bleed off line to reduce wear and tear on valves. Location of choke should be considered. The returns should be routed to a measuring tank.

6.5 Rig-up, Commissioning, and Testing

6.5.1 Project Coordination

A single point of contact should be identified early in the project to coordinate activities associated with the rig-up, commissioning, testing, and rig-down phases.

6.5.2 Managed Pressure Drilling Rig-up

6.5.2.1 MPD surface equipment should be hooked up per site-specific P&ID. Any deviation should be documented. A critical spares and equipment analysis should be conducted, and adequate inventory should be available on-site.

6.5.2.2 The P&ID should include the site-specific BOP stack-up.

6.5.2.3 The P&ID diagram should at a minimum include a valve numbering and representation of MPD-related equipment and flow paths and related rig equipment.

6.5.2.4 To facilitate valve and pressure management during MPD operations, a PFD diagram should be prepared for each flow path.

6.5.2.5 The P&ID or PFD and BOP stack-up diagrams/screens should be available in the driller's cabin.

6.5.3 Equipment Installation and Test Plans

The following points should be considered in developing an integrated test plan to ensure that equipment is ready for MPD operations.

a) Off-line pressure testing MPD equipment prior to shipment to rig or on deck once built up; suitable riser connector test flanges, segregated space, test pump, pressure gauge, and chart recorder, etc.

b) Off-line pressure testing MPD equipment individually prior to unitization; suitable test flanges, segregated space, test pump, pressure gauge, and chart recorder, etc. Development of rig site pressure testing plans utilizing approved MPD P&ID diagram to create standard flow path configurations (drilling, tripping, RCD change-out under pressure, etc.) and marked-up test flow paths and barriers including verification of all related pressure gauge systems (BOP mounted, well control systems, surface systems [mud pumps, cement pumps, etc.]).

c) Off-line pressure testing of surface lines, MPD-related manifold valves, flow hose and pressure relief hoses and their connections at rig site; suitable test flanges, specification breaks, etc.

d) Off-line integrity and function testing of MPD riser components control systems and MPD manifold control systems.

e) Off-line testing, where possible, of overpressure protection systems (specification breaks, wellbore, riser, surface lines and manifolds, etc.).

f) Off/online function and pressure testing once equipment installed in/on riser to prove integrity of flow hose connections/goosenecks and MPD flow valves.

g) Consideration should be given to facilitating the testing of the MPD components by utilizing a BOP test ram, test packers, inflatable packers, etc.

h) Online RCD stripper and bearing integrity tests upon installation of same into string, both at initial rig-up and subsequent operations to remove and reinstall same as a result of tripping, replacement due to leakage, etc.

i) Agreed plan regarding testing frequency—e.g., on initial deployment, as per agreed test plan, after installation and cementing of casings and liners.

j) Cased hole flow testing to ensure proper operation of MPD equipment, identify and fingerprint any applicable flow characteristics and operating parameters.

6.5.4 Managed Pressure Drilling Commissioning

6.5.4.1 A site-specific pressure test and commissioning procedure is critical. It shall reflect the system design to prevent damage to the system and should be linked to specific equipment installed per the P&ID or PFD.

6.5.4.2 Prior to pressure testing, the MPD system shall be visually inspected and checked against the P&ID or PFD to confirm that it is safe to test.

6.5.4.3 Pressure testing shall be conducted at the wellsite in conformance with procedures approved by the operating company, drilling contractor, and service company.

6.5.4.4 The MPD circulating system acceptance testing results should be compared to the pre-job modeled back-pressure limits and downhole operating windows to ensure that the pre-drill hydraulics modeling is still valid and that MPD is still a valid solution for drilling the hole section. Any required corrective action shall be undertaken prior to commencement of operation.

6.5.5 Control System Function Tests

Testing MPD surface systems ability to meet the design requirements of the well should be conducted.

These tests may need to be repeated for each hole section to ensure optimal system performance.

6.5.6 Rotating Control Device Function Tests

Testing should be conducted after installation.

Fingerprinting of drag when stripping in and out should be performed.

6.5.7 Pressure and Flow Testing

6.5.7.1 Test frequency should be in accordance with local regulatory and or company standards, whichever is most stringent. As a minimum, the following testing should be included.

a) At initial installation (per well) the entire system should be tested.

b) When equipment has been modified, repaired, or replaced, the relevant equipment should be tested.

c) The riser isolation valve(s) and primary flow paths to the choke isolation valve (MPD and/or rig choke manifold) should be tested with the same test frequency as the BOP.

d) In case the standpipe is tied in to the distribution manifold, the isolation valves should be tested with the same test frequency as the BOP.

6.5.7.2 Surface equipment should be low-pressure and high-pressure tested. The high-pressure test should, as a minimum, be to the maximum MPD operational pressure.

6.5.7.3 Equipment exposed to high flow velocities should be inspected on a regular basis using industry-accepted practices to monitor for materials erosion.

7 Drill String

7.1 General

7.1.1 This section addresses issues related to drill string components exposed to well effluent during MPD operations. The term “drill string” refers to both jointed and coiled tubulars. The term “drill pipe” refers to traditional drill pipe with tool joints and tubing with connections suitable for drilling service.

7.1.2 Integrity of the drill string means that there is pressure isolation between circulated fluids inside the drill string and wellbore fluids or the atmosphere outside the drill string, except where otherwise designed. This requires pressure integrity of all components from the swivel to the drill bit during rotary drive applications, from the top drive unit to the drill bit during top drive applications, and from the rotary joint on the coiled tubing reel to the drill bit during coiled tubing drilling applications.

7.1.3 Unless otherwise stated, drill string design should be carried out in accordance with applicable design standards, recognizing that this is a more critical service than standard applications.

7.2 General Requirements for Drill Pipe

7.2.1 In a jointed pipe MPD project, the drill pipe is a critical component of the flow control system. The quality and condition of the pipe (internal and external, as well as the tool joints) is key to not only achieving the well objectives, but can also negatively impact the well barrier elements (the RCD and the NRV).

7.2.2 The transition from the drill pipe outer diameter (OD) to tool joint upset OD should be gradual. This should also be taken into consideration if HW pipe with a mid-joint upset will be used as part of the MPD string.

7.2.3 The need for gas tight connections should be considered in cases where the use of gasified fluids is planned.

7.2.4 Appropriate drill pipe and tubing grades should be used for wells classified as sour.

7.2.5 API identification grooves and internal plastic coating are normally accepted modifications to the drill pipe used in conventional drilling operations. Although not directly related to the integrity of the drill string, these can have an impact on the integrity of critical components of the pressure containment system.

7.2.6 Wear-resistant alloy overlay should be smooth. Application of proud tungsten carbide hard banding is not recommended because of the potential damage it causes to the casing and to the RCD’s sealing element in MPD applications.

7.3 General Requirements for the Bottom-hole Assembly

7.3.1 A nonported NRV should be installed as close to the bit as practical. NRVs should conform to API 7NRV.

7.3.2 In MPD operations, a minimum of two NRVs should be run in the drill string.

7.3.3 Prior to deployment, each NRV should have a low-pressure test and then should be tested to the maximum anticipated working pressure.

7.3.4 The location of the drill string jar should be carefully considered with respect to the RCD.

7.3.5 If coring or under-reaming operations are to be performed, the special requirements for these operations should be considered when selecting and positioning NRVs.

7.4 Drill String Design

7.4.1 Drill string design is important as it impacts many aspects of the operation. The design shall meet the needs of the normal operations and contingency plans.

7.4.2 The usage of PWD in the BHA should be considered as it monitors downhole pressure during the operations. The ability to retrieve pumps-off PWD data should also be considered.

7.4.3 A circulation sub can provide flexibility and/or allow for contingency solutions.

7.4.4 Another key aspect, as annular back-pressure is applied, is the usage of drill string isolation valves (NRV and/or drop-in check valves for contingency plans) and annular isolation tools or materials during tripping. A barrier and safety margins analysis should be done for all the operations (e.g., tripping and connections).

7.4.5 Full-open safety valves shall be available. These valves may be run in-hole below the RCD and subjected to annular pressure.

8 Drilling Fluid Considerations

8.1 General

8.1.1 Drilling fluid design is the key aspect during SBP operations as it governs the equivalent circulating density (ECD) management. Drilling fluids used in MPD operations are selected using the same criteria as drilling fluids used in conventional drilling, except mud weight. The weight selection and measurement during operations are a key aspect, as they affect the BHP and surface annular back-pressure. The design shall account for the uncertainties in the pore pressure prediction as it can lead to different fluid weight and back-pressure.

8.1.2 To ensure adequate hole cleaning, a proper understanding of cuttings transport in this environment is necessary. Inadequate hole cleaning can result in the circulation returns path becoming packed-off, limiting the ability to circulate. The inability to circulate due to cuttings pack-off can result in a “stuck” drill string or well control incident.

8.1.3 When making any adjustments to mud properties, take into account effects on ECD management.

8.1.4 Hydraulic simulations shall be done to determine the correct hydraulic modeling as input to the MPD application. A sensitivity analysis shall be performed to verify pump pressure, SBP, anchor point, etc.

8.1.5 A thermal and hydraulic simulation shall be performed to verify if equipment and material used are fit-for-purpose.

8.2 Compatibility with Other Systems

The compatibility of the drilling fluid, with other components of the circulating system, should be reviewed.

Compatibility of RCD’s stripper element compound with the drilling fluid should also be reviewed.

8.3 Kill Weight Fluids

8.3.1 Operational and/or safety considerations can require the killing of a well, which is being drilled, using MPD techniques. Sufficient material should be available on-site to be able to kill the well. In the context of this operation, kill fluid refers to the fluid used to bring the well to a static overbalanced state without SBP. There are several options for how to accomplish this. It may be possible to balance or kill the well without displacing the entire system to another mud weight (e.g., balancing the well to trip without closing the blind rams); however, the risk associated with well bore conditions and fluid swapping should be considered. There should be sufficient mud or mud material available to provide 100 % excess of the required volume to balance the well.

8.3.2 Degradation of the kill fluid (gel strength if weighting material is required), lost circulation issues, and the effects of cold weather/HPHT operations should be taken into account when managing the kill fluid system.

8.3.3 If weighting or lost circulation materials (LCMs) are required to kill the well, consideration should be given to the ability to successfully circulate these materials through the BHA and MPD surface equipment. Circulating subs above flow restrictions may be necessary.

9 Well Control and Well Integrity

9.1 General

9.1.1 This section describes the principles, responsibilities, and equipment necessary for maintaining appropriate well integrity and well control during MPD operations.

9.1.2 When drilling a well using SBP, the primary well barrier may consist of additional well barrier elements (e.g. RCD, piping, MPD choke manifold, etc.) as compared to conventional operations. BHP will be expressed as follows:

BHP = hydrostatic pressure + annular friction + surface friction + SBP

9.1.3 The MPD system controls the annulus back-pressure. If the MPD system fails to maintain the required BHP operating range, a well control situation can occur. When drilling with a hydrostatically overbalanced column of fluid, well barrier elements remain the same as conventional drilling. However, when drilling with a hydrostatically underbalanced column of fluid, the primary well barrier will include MPD equipment such as the RCD and MPD choke manifold.

9.1.4 The secondary well barrier remains the same for MPD operations as for conventional drilling operations.

9.1.5 Managed pressure operations introduce additional well barrier elements to conventional operations. The presence of these additional well barrier elements warrants inclusion in the risk assessment.

9.2 Well Barrier Elements

9.2.1 General

9.2.1.1 In conventional drilling, well barrier elements may include, but are not limited to, the following:

a) fluid column;

b) marine drilling riser package;

c) LMRP;

d) casing;

e) casing cement;

f) wellhead;

g) drilling BOP.

9.2.1.2 MPD introduces additional well barrier elements as illustrated in Figure 5; these may include, but are not limited to, the following:

a) RCD;

b) riser isolation tool (annular);

c) termination joint;

d) flow return spool;

e) flow valves;

f) flexible flow lines;

g) MPD choke manifold;

h) surface valves (e.g., check valve after BPP);

i) drill string w/NRVs.

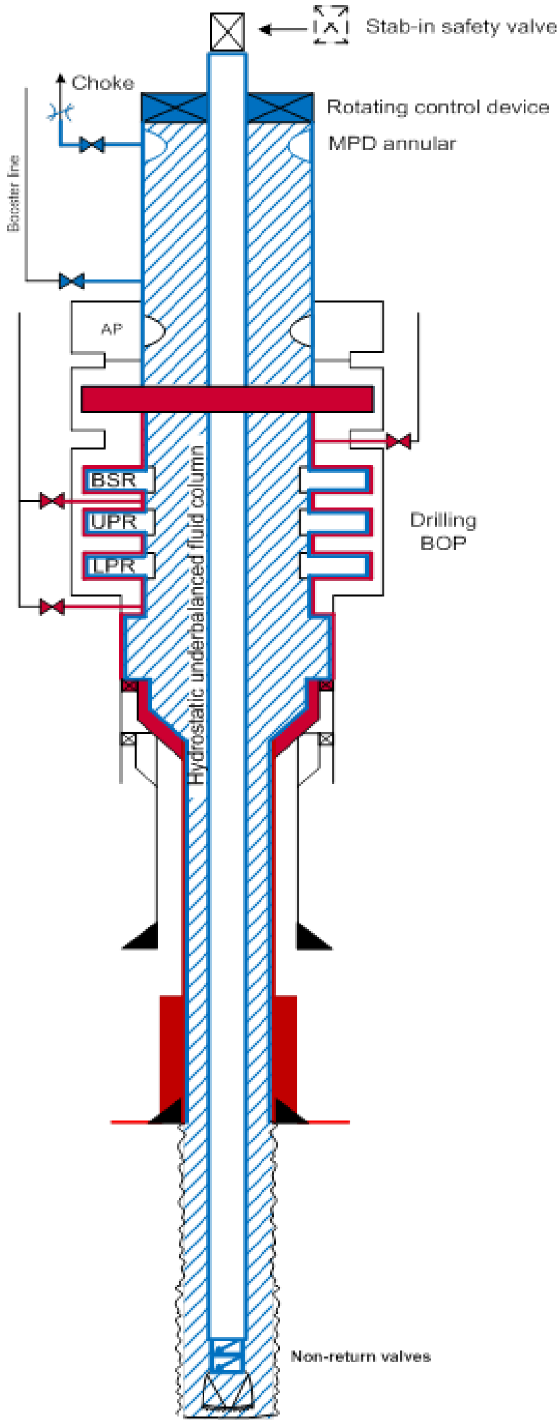
9.2.1.3 MPD well barrier elements shall be rated to withstand the maximum anticipated pressure expected for planned operations and a safety factor should be applied.

9.2.1.4 Upon initial rig-up and installation of MPD well barrier elements, the integrity and functionality shall be verified by means of a pressure test to at least the maximum anticipated pressure and a function test of those well barrier elements that require activation. An example of when to perform this test is prior to drilling out the casing shoe prior to commencing MPD operations.

9.2.1.5 Due to operational restrictions, it may be feasible only to test replacement sealing elements to the maximum available SBP as opposed to maximum anticipated pressure.

9.2.2 Well Barrier Schematics

Both primary and secondary well barrier shall be identified for all MPD operations. Well barrier schematics should be made to identify well barrier elements for each phase in the MPD operation (drilling and tripping the drilling BHA, running a completion, etc.) when there are changes in the barrier. Figure 5 shows an example of well barrier elements while drilling in MPD mode.



Well Barrier Elements	Comments
Primary Well Barrier	
Static underbalanced fluid column	
Casing*	
Wellhead*	
Marine riser	Below telescopic joint
Drilling BOP*	
Rotating control device	
Drilling NRVs	Minimum two
Drill string or completion string	
MPD annular	
MPD choke system	Including control system
Secondary Well Barrier	
In situ formation	
Casing cement	
Casing [a]	
Wellhead [a]	
Drilling BOP [a]	

[a] Common well barrier element.

Figure 5—Well Barrier Schematic Example

9.3 Managed Pressure Drilling Operations Matrix

9.3.1 The intention of this section is to:

— describe the operating range within the primary well barrier,

— define the shift from primary well barrier to secondary well barrier, and

— determine when to execute well control with the secondary well barrier.

9.3.2 Unplanned influx incidents should be categorized and reported in accordance with local operator policy and consistent with regulatory requirements. An influx into the wellbore below the planned limits is not considered a well control event.

9.3.3 A decision-making guidance tool should be utilized to graphically illustrate and communicate to the MPD crews when and what action is required. Table 1 shows an example of such a tool.

Table 1—Example of Managed Pressure Drilling Operations Matrix

MPD Operations Matrix		Surface Pressure			
		At Planned Drilling Back-pressure	**At Planned Connection Back-pressure**	**> Planned Back-pressure and < Back-pressure Limit**	**≥ Back-pressure Limit**
Influx Volume	No influx	Continue drilling	Continue operation	Continue operation; adjust system to decrease WHP	Secure well; evaluate next planned action
	≤ Operating limit	Continue drilling; adjust system to increase BHP	Continue drilling; adjust system to increase BHP	Continue drilling; adjust system to decrease WHP and increase BHP	Secure well; evaluate next planned action
	< Planned limit	Cease drilling; adjust system to increase BHP	Adjust system to increase BHP	Secure well; evaluate next planned action	Secure well; evaluate next planned action
	≥ Planned limit	Secure well; evaluate next planned action	Secure well; evaluate next planned action	Secure well; evaluate next planned action	Secure well; evaluate next planned action

Definitions

Back-pressure limit: Back-pressure limit should be calculated and can be limited by riser limitations, casing design, surface equipment limitations, formation break down pressure, etc.

Operating limit: The limit at and below which drilling can continue.

Planned limit: The limit at and above which MPD ceases and a transition to well control operations is required.

9.3.4 The MPD operations matrix should be project specific and based on the design limitations of the actual equipment that will be used during project execution and any formation related constraints. A risk-based approach based on, but not limited to, the following is recommended:

a) surface equipment;

b) riser system;

c) size of drilling window;

d) wellbore geometry;

e) productivity;

f) influx type;

g) drilling fluid type;

h) health, safety, and environment (HSE).

Procedure for transitioning well operations between well control and MPD mode should be based on pre-well engineering and planning.

9.4 Contingency Plans

Procedures shall be in place prior to start of the MPD operations and should reflect potential well control incidents identified in risk management processes. Table 2 describes examples of incident scenarios for which action procedures should be available (if applicable) to deal with the incidents should they occur.

Table 2—Incident Scenarios

Item	Description	Comment
1	Bottom-hole or surface pressure and/or flow rates detected that can lead to the pressure rating of the RCD (static or dynamic), riser or the capacity of the surface separation equipment being exceeded	
2	NRV failure, influx into work string during making connection or tripping in live well	
3	Leaking connection below drilling BOP	
4	Leaking RCD, flow line or flow line valve	Seal elements, connection to flow line, drilling BOP or riser system, spools, spacers, adapters, etc.
5	Erosion or washout of choke	Consider the case where isolation for repair of the choke cannot be achieved
6	Failure of surface/subsea equipment downstream of the RCD	This can be leaks or plugged equipment and lines
7	Work string failure, washout or twist-off	Consider pipe light scenario and contribution from additional NRVs in the drill string; evaluate risk for pipe failure based on well path/dog leg severity
8	Emergency shut-in	
9	Kick	Including criteria for shut-in
10	Lost circulation	
11	H_2S in the well	
12	Loss of rig power or MPD control system	
13	Simultaneous kick and loss situation	
14	Stuck pipe	
15	Emergency disconnect	
16	Choke-line, kill-line plugging	
17	Inability to retrieve RCD seal assembly	
18	Riser gas	
19	Failure of MPD annular	During RCD sealing element change-out

9.5 Well Control Action Drills

Before an MPD operation is started, well control drills should be conducted according to the predefined well control procedures. Examples of well control drills are provided in Table 3.

Table 3—Example of Well Control Drills

Type	Frequency	Objective	Comment
Pressure rating of the system upstream of the choke or the capacity of the surface equipment being exceeded	Once per well with crew on tour	Procedure training	To be done prior to running-in-hole (RIH)
Leaking NRV, influx into work string on making connection or tripping in live well	Once per well with crew on tour	Procedure training	To be done prior to RIH
Leak in RCD	Once per well with crew on tour	Procedure training	To be done prior to RIH
Leak in equipment downstream RCD	Once per well with crew on tour	Procedure training	To be done prior to RIH
Leak in drilling BOP lower connector	Once per well with crew on tour	Procedure training	To be done prior to RIH
Choke drill	Once prior to starting MPD operations with crew on tour	Practice in operating the adjustable choke with pressure in the well	Before drilling out of the last casing prior to MPD operation
H_2S drills	Prior to drilling into a potential H_2S zone/reservoir	Practice in use of respiratory equipment	All relevant personnel to have necessary training if H_2S is known to be present
Transferring between well control and MPD equipment	Once prior to starting MPD operations with crew on tour	Practice in changing from MPD mode to standard well control mode and back (in case of a kick situation)	Before drilling out of the last casing prior to MPD operation

9.6 Use of the BOP/LMRP during Managed Pressure Drilling Operations

9.6.1 When planning to use a BOP/LMRP element for any MPD operations, a risk analysis shall be performed.

9.6.2 Although the rig's BOP stack is part of the secondary barrier and installed on the rig for well control events, a secondary barrier element may be used, subject to a detailed risk analysis, for limited remedial operations (e.g., stripping through annular to change out RCD seal element or sealing off wellbore during pulling/running BHA). The secondary barrier elements should not be used for planned events in MPD operations except as addressed in the detailed risk assessment.

9.7 Roles and Responsibilities

9.7.1 The operator shall have a plan in place to address the transition between MPD operations and well control. Individual roles and responsibilities of personnel engaged in offshore MPD operations shall be clearly defined in the plan. It is critical that the rig contractor, the MPD service contractor (if one is used), and the operator's on-site representatives be involved in the creation of the plan. The operator's on-site representative and the rig contractor's representative shall have the authority to execute this plan immediately. To ensure understanding, the roles and responsibilities shall be fully detailed in organization charts and communicated to personnel during the on-site orientation briefing.

9.7.2 Competent personnel should be used for MPD operations. Key personnel involved in the operations should be adequately trained in MPD and well control, and the training and competency should be documented. Personnel in the process of becoming competent should be supervised by competent personnel.

9.7.3 Refer to IADC *Underbalanced and Managed Pressure Drilling Operations—HSE Planning Guidelines*.

9.8 Riser Gas Handling

9.8.1 SBP MPD on a floating rig requires use of an RCD to close off the top of the riser. As a result, flow and pressure changes caused by gas expansion in the well below the BOP or in the riser can be more easily controlled than is the case for conventional, open-to-atmosphere drilling operations.

9.8.2 A well control event can thus trigger the immediate need for BOP closure (i.e., the primary barrier is no longer intact, and the secondary barrier is therefore required).

9.8.3 Since such primary barrier insufficiency may occur after a known, limited volume of gas influx has been circulated into the riser above the BOP, use of the BOP will permit only control of the well; a separate procedure may be needed to control pressures and flow associated with any further expansion of the gas already in the riser.

9.8.4 In conventional operations, the crew and rig may rely on the rig diverter system to protect them from the consequences of uncontrolled gas expansion in the riser. However, in SBP MPD, the RCD prevents use of this practice. As a result, the MPD system and operating practices shall address the manner in which such events are managed to provide equivalent or greater protection for the crew and rig. The MPD system and operating practices shall include the following.

a) Specific documentation of pressure and flow control that are required to manage potential worst-case conditions associated with removal of gas influx volumes permissible without compromising the primary barrier limit.

b) Specific documentation to confirm the adequacy of MPD equipment (including the pressurized riser system) to provide these quantified pressure and flow control capabilities.

c) Specific documentation of contingent procedures to be used in the event of unexpected exposure to conditions that reach or exceed system operating limits.

10 Managed Pressure Drilling Operational Guidelines

10.1 General

This section provides guidance on the operational phase of the MPD project.

10.2 Training

10.2.1 General Training

Documented competency levels should be available for personnel involved in the MPD operation as required by the operator.

MPD training should be carried out prior to the operational phase to ensure that personnel understand all aspects of the MPD operation. This training may be classroom, simulator, or rig based. Example competency levels can include awareness, engineering simulation, and rig site operations.

10.2.2 Rig-site Training

In addition to the general training, an MPD rig site training program should be developed and can include the following:

a) equipment familiarization;

b) well control and flow path practice;

c) standard operating procedures;

d) contingency procedures;

e) drills and emergency preparedness;

f) communications protocols;

g) transition from and to conventional operations.

10.3 Drilling and Related Operations

10.3.1 When drilling using MPD with SBP, the objective is to maintain dynamic and static wellbore pressures within the operational window. The following points can also be achieved.

a) Identification of small losses and influxes, enabling the use of a smaller kick tolerance compared to a conventional operation.

b) The ability to measure formation pressures (pore and fracture).

— Care should be taken in tight or depleted formations where the formation cannot flow.

— In the event such tests are performed, care should be taken to ensure that potential influxes are fully understood before continuing operations. Conventional volume control practices still apply.

— Prior to initiating a pore pressure test by lowering BHP the procedure and risk assessment should be reviewed. See 8.3 for actions to control influxes.

— Prior to initiating a fracture test by increasing BHP, the procedure should be reviewed.

c) Drilling fluid compressibility should be taken into consideration while performing these tests. If fracture gradient allows, increasing SBP might allow better management of a gas influx.

10.3.2 Ensure that there is a sufficient operating window to safely carry out these operations. Points to consider can include the following:

a) communication;

b) tripping speeds (in relation to swab and surge);

c) connection procedures;

d) influx detection method;

e) mud properties;

f) pumps limitations and available mud volumes;

g) barriers;

h) contingency plans;

i) riser limitations;

j) heave;

k) surface lines and manifold limitation.

10.3.3 Fingerprinting of normal and contingency operations should be performed prior to and during drilling operations (e.g., connections).

10.3.4 Consider whether returns will be taken through the MPD choke while drilling out the cement shoe. Consider whether choke is adequately sized to prevent blockage.

10.4 Wellsite Supervision

All parties involved in the operations should review their existing personnel to identify any additional training and resources that may be required to ensure that MPD operations are carried out safely.

10.5 Metocean and Environmental Considerations

10.5.1 Operating Conditions

The MPD system will be designed to operate in three operating modes normally encountered in offshore drilling operations as defined below (see Figure 6).

Recommended limits for design and operation of marine drilling riser systems are discussed in API 16Q. API 16Q defines recommended operating and design guidelines for the three operating modes.

10.5.1.1 Drilling Mode

The drilling mode is a combination of environmental and well conditions in which normal drilling activities can be safely conducted including drilling ahead, tripping, under-reaming, circulating, etc. Special operations such as casing, cementing, completion activities, or a formation integrity test (FIT) can dictate more restrictive operating limits.

10.5.1.2 Connected Nondrilling Mode

In this mode, preparations should be made to suspend drilling operations and, if necessary, preparations made to shut in the well and disconnect the riser.

10.5.1.3 Disconnected Mode

If environmental conditions exceed the limits for safe operation in the connected nondrilling mode, the riser should be disconnected to avoid possible damage to surface or subsea equipment.

10.5.2 Dynamically Positioned Drilling Vessel Considerations

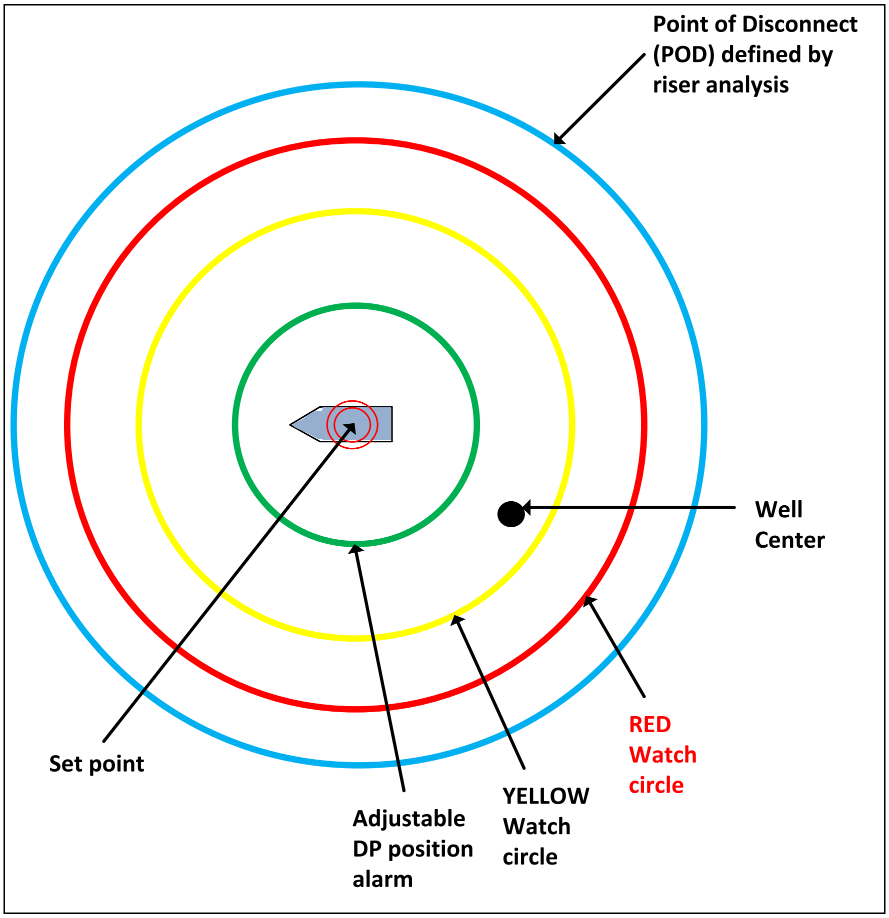
A dynamically positioned (DP) vessel may be required to disconnect the LMRP and riser from the BOP in the event of a loss of station resulting from:

— loss of power (drift-off),

— position reference fault (drive-off), or

— DP control system fault (drive-off).

These limits (watch circles) are established for each well and should be considered during the MPD operations HAZOP and well planning.



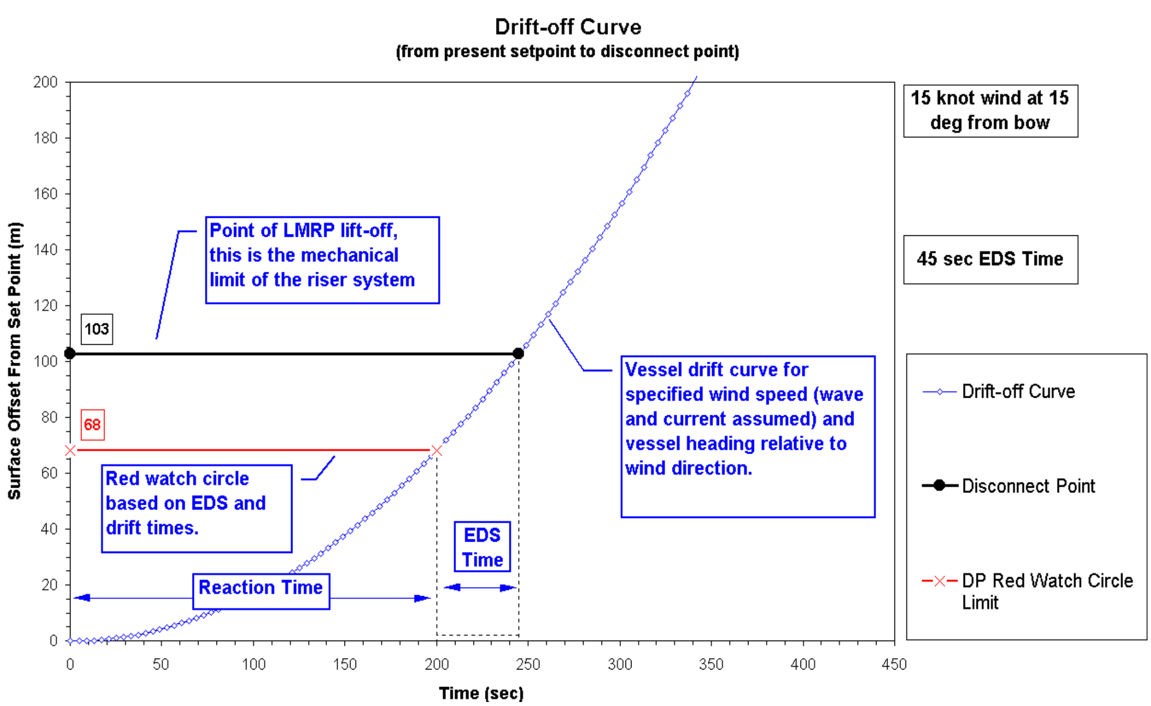


Figure 6—Example of Dynamically Positioned Watch Circles and Drift-off Curve

Annex A
(informative)

Influx Management with Surface Back-pressure Managed Pressure Drilling

A.1 Purpose

This annex provides guidance for planning to perform influx management using the MPD system. This annex addresses MPD operations intended to avoid an unintentional influx of formation fluids. In these operations, any influx shall be safely contained using an appropriate process.

This annex provides information for planning and executing influx management using managed pressure techniques with surface back-pressure and applies to rigs with both surface and subsea blowout preventers (BOPs).

A.2 Scope

This annex is designed to cover dynamic influx management operations that follow the parameters established within the MPD operations limits.

The annex covers the three types of MPD influx management operations as follows:

— influx termination and removal using MPD influx management;

— MPD influx termination (with conventional influx removal);

— MPD-assisted conventional shut-in.

This annex does not cover underbalanced (refer to API 92U) or conventional well control operations.

A.3 Introduction

In MPD, well design barrier integrity follows conventional drilling operations principles with a unique distinction. During closed loop MPD operations, the primary barrier is achieved through the combination of fluid hydrostatic pressure, annular friction pressure, and surface back-pressure.

In case the surface pressures and influx volumes are sufficiently low, the influx flow can be terminated by increasing bottom-hole pressure using the MPD system. Similar in concept to the first circulation of the driller's method, the influx can be removed from the well using the MPD system, adjusting the MPD choke to maintain constant BHP. There is no need to shut in the well or stop circulation at any point. Additionally, it may be unnecessary to increase the drilling fluid weight. This method provides significant benefits over conventional well control. These include the influx being removed from the well much more quickly and maintenance of annular friction pressure, which prevents increased influx flow that results from decrease in BHP when pumps are shut down.

Management of an influx can be split into three execution phases: detection, control, and circulation.

With conventional well control, an influx is detected and then the pumps are shut down before the secondary barrier (blowout preventer) is closed to secure the well. The influx is then removed from the wellbore. If the drilling operation uses MPD, MPD influx management can be used. MPD influx management offers advantages compared with conventional well control techniques during all three phases of influx management.

a) MPD systems can provide early kick detection, allowing kicks to be detected earlier than with traditional drilling indicators (such as return flow variation and pit gains).

b) An influx can be controlled while continuing to circulate down the drill string by increasing SBP. A circulating response has the following advantages compared to a noncirculating response in which the pumps are stopped and the BOP closed.

— Bottom-hole pressure is not reduced.

— The influx volume inside the wellbore is reduced as the pressure is increased by adding drilling fluid rather than formation fluid downhole.

— The influx is dispersed downhole.

— The pumps do not need to be restarted. This can require difficult choke manipulation to maintain constant bottom-hole pressure, especially in narrow margin wells where annular friction cannot be neglected.

— The possibility of an automated response can be considered less complex.

— The resulting annular pressures for a particular kick intensity can be lower when compared with shutting the well in for the same influx intensity.

— Drill string movement can be maintained without compromising the sealing device (annular BOP in conventional applications versus an RCD in MPD applications), reducing stuck pipe risk.

c) An influx can be circulated out using the MPD system with more precise and consistent control when compared to conventional methods.

— PWD data, if available, may be received while circulating.

— The amount of time to recover from an influx may be reduced, due to higher circulation rates.

— Reduction of surface pressure since there is more annular friction.

— The secondary barrier is preserved for situations of higher severity.

— Avoidance of adding choke line friction pressure (CLFP) to BHP during circulation in operations with a subsea BOP stack.

In combination, these factors can reduce influx volume and improve the accuracy of influx circulation. This can reduce pressures at surface and the casing shoe and may allow smaller kick tolerance values to be accepted.

MPD influx control techniques require upfront planning, procedural changes, and training. Conventional well control techniques remain available if the limits of the MPD influx management operation are reached or in the event of a problem with the MPD system. If the well is closed in conventionally with the BOP, MPD can still be used to assist the shut-in to avoid a reduction in BHP.

A.4 Planning and Engineering

A.4.1 Well Construction Interface Document

Bridging documents should cover the influx detection and circulation phases.

NOTE API 97 and API 97L are guides for bridging documents for onshore and offshore interventions.

A.4.2 Equipment Considerations

A.4.2.1 System Design Related to Influx Management Operations

A.4.2.1.1 General

Section 6 provides an overview of the recommended equipment required for SBP MPD operations. Section A.4.2 provides additional guidance when planning to perform influx management using MPD equipment. For equipment considerations, refer to the relevant API documents as well as the MPD-specific documents.

The design of the MPD system should be examined specifically for influx management. The risk associated with the circulation of formation fluids should be evaluated, including the circulation of hydrocarbons and corrosive gases. The formation of hydrates should be considered prior to commencing operations.

The additional considerations listed in A.4.2.1.2 through A.4.2.1.12 are common to all MPD system configurations, whether using a surface or subsea BOP.

A.4.2.1.2 Marine Drilling Riser System for Subsea Applications

Additional influx circulating pressure considerations shall be assessed to ensure the drilling riser system can be safely used to circulate out influxes.

Marine drilling riser system design and fluid interactions shall be assessed to allow circulation of influxes in a sour gas field. See API 16F for information on marine drilling riser design.

A.4.2.1.3 MPD Annular Isolation Device for Subsea Operations

For subsea stack applications, consideration should be given to configuring the system so that MPD influx returns can be routed to the MPD choke under a closed MPD annular or equivalent. This may be achieved by installing a sealing device below the RCD. This will alleviate concerns about pressure rating of the RCD or sealing element leakage during influx management operations.

A.4.2.1.4 Riser Pipe above Rotating Control Device

Consideration should be given to the implication of circulating out a potential hydrocarbon influx at surface using the RCD element(s). The potential risk is gas release channeled directly to the rotary table.

A.4.2.1.5 Rotating Control Device (RCD)

The maximum allowable working pressure (MAWP) of the RCD and its ancillaries should be taken into consideration when planning to bring an influx to surface. Consideration for an operational safety factor should be given prior to the operation.

The condition and capability of the RCD elements should be considered before bringing an influx to surface. Refer to 6.2.3 for examples of factors that can reduce the pressure capability of an RCD.

A.4.2.1.6 Pressure-relief Valves (PRVs)

The set point of the PRVs should be considered prior to bringing an influx to surface.

During the planning stage, consideration should be given to the PRV sizing, discharge line sizing, route, and the discharge point should be reviewed to ensure they consider influx management operations. The maximum allowable working pressure of the system shall be limited to the lowest rated element; the PRVs shall be set to protect the system. See API 14C (or ISO 10418) for general considerations and safety analysis to be performed in the planning and engineering phase, as applicable.

The PRV selection and setup should consider the type of fluid circulated during the influx circulation.

A.4.2.1.7 MPD Choke Manifold

During the planning phase, the well parameters should be assessed for hydrate prevention. If required, a suitable injection point should be available upstream of the MPD choke manifold.

Consideration should be given to mitigating choke erosion.

A.4.2.1.8 Control Systems

The MPD control panel should have the ability to centrally control and monitor MPD well and equipment parameters required to perform influx management operations.

The control system’s reliability to perform influx management operations should be assessed. Such an assessment of the control system’s reliability can be done by performing testing in a flow loop or in a multiphase simulator, in addition to performing any other factory acceptance tests.

A.4.2.1.9 Flowmeters/Flow Monitoring

Flow metering/monitoring in and out of the well is required for influx management.

NOTE 1 Gas volume fraction in Coriolis meters can lead to erroneous readings and can impact your influx detection capabilities. Meter placement should be considered relative to choke location.

NOTE 2 A flowmeter is only required for influx management on the outlet of the well; for the inlet pump stroke, counting is acceptable.

A.4.2.1.10 Pipework and Hoses

Compliance to sour service rating should be considered if influx management operations are planned on wells where there is a known (or possibility of) sour environment (see NACE MR0175/ISO 15156).

Hoses used for pressurized hydrocarbon service shall be in compliance with applicable industry standards for fluid composition, sour service, pressure rating, and temperature.

The sizing and pressure rating of all flowlines intended to be used for influx management shall be fit-for-purpose for the planned operational parameters. This includes the piping from MPD choke manifold into the MGS.

When planning to do MPD influx management with a surface stack, installation of a secondary flowline below the rig annular to route returns into upstream tie-in point of the MPD choke manifold should be assessed.

NOTE The purpose of this line is to isolate the RCD during influx management operations.

The sizing and pressure rating of any secondary flowline intended to be used for influx management should be fit-for-purpose for the planned operational parameters. (This may require an additional drilling spool).

An expedient routing of flow paths and minimizing personnel exposure when using the MPD choke manifold and equipment for influx management should be considered.

A.4.2.1.11 Hydraulics Model

Hydraulics models with influx simulation capabilities and wellbore visualization tools can be advantageous for the planning of MPD influx management operations. If a hydraulics model is to be used, additional consideration should be given to verification of input parameters and accuracy of calculations.

A.4.2.1.12 Mud Gas Separator (MGS)

The combined liquid/gas handling capability of the MGS shall be determined, as this has a direct impact on the size of an influx that the surface MPD system can handle and the rate at which it can safely be dealt with at surface. The capability of the MGS can form an additional boundary when developing the safe operating limits and determining the maximum influx conditions that can be handled by the MPD system. Flow rate circulation of influx shall be below the MGS processing capacity. During a dynamic operation such as influx management, there shall be a means to monitor the integrity of the liquid seal to ensure that MGS limits are not exceeded.

The addition of a fill-line (hot-line) into the MGS and proper interface to pits and pumps should be considered.

NOTE The impact of contaminated fluid (lower density hydrocarbon) can reduce the capacity of the MGS, due to lower hydrostatic pressure.

The MGS should be designed in accordance with industry-recognized standards, such as but not limited to ASME *BPVC*, Section VIII or BS PD 5500.

Remote level and pressure measurement capabilities should be evaluated. Liquid level measurement can alert the driller and MPD operator to reduce flow into the vessel so as not to overwhelm the vessel during influx management. Pressure measurement on the vessel can alert the driller and MPD operator that the vessel pressure is close to exceeding the liquid U-seal capability.

Remote monitoring should be used to confirm that MGS limits are not exceeded.

An appropriate wall thickness monitoring program should be in place based on well conditions to monitor the condition of pipe between the MPD choke and the MGS inlet.

EXAMPLE Periodic inspections between jobs and projects.

A.4.2.2 Equipment Qualification

The processes required by classification societies are beneficial to ensuring that the MPD system design and installation is fit for its intended or planned operations, including influx management. When not using a classification society, the following process is recommended for MPD equipment qualification.

a) The following actions should be considered prior to mobilization:

   — reviewing equipment data packages for compliance with recommended industry standards;

   — reviewing that equipment is good for the service planned (H_2S or CO_2 sour service);

— reviewing compliance with electrical zoning classification planned for onsite equipment location;

— reviewing of control and instrumentation systems;

— reviewing equipment maintenance program and pre-mobilization pressure test to MAWP.

b) The following actions should be considered on location prior to operation:

— having a qualified electrician perform an electrical inspection;

— testing and validating instrumentation and data transfer;

— pressure testing to planned maximum job parameters, including influx circulation parameters;

— reviewing of the MPD control system and testing of critical alarm/warning functions;

— performing an influx exercise and ensuring the MPD system detects and reacts as planned.

A.4.3 Process Safety and Reliability Studies

As discussed in 5.4, safety studies and reviews should be extended to influx management operations. For MPD operations where influx management is planned, the increased pressures, volumes, fluid composition, and dealing with hydrocarbons at surface should be revisited and addressed during the process safety and reliability studies.

Line routing shall be reviewed for gas at the surface. Consideration should also be given to the condition of RCD seal elements, and it may be beneficial to use empirical (field) data to schedule RCD element changes.

The IADC UBO/MPD HSE Guidelines and API 14J provide details on conducting HAZID, HAZOP, FMEA, and other safety studies for MPD operations.

A.4.4 System Installation

A.4.4.1 General

This section gives additional guidance for planning to perform influx management with an MPD system. This section assumes that a detailed P&ID has been developed and that equipment and layout drawings have both been reviewed as part of a safety study process. Any changes made to a previously reviewed MPD system to incorporate influx management should be subjected to a safety study process via a management of change process.

A.4.4.2 Equipment Layout and Zoning

5.3 recommends reviewing electrical zoning modifications during FEED. When planning to do influx management, consider the impact on hazardous area zoning. See API 500 or API 505 for more information on area classification for electrical installations.

A.4.4.3 Flare and Vent Stacks

For onshore operations, the routing and discharge point of the MGS flare line should be reviewed, and a continuous flare ignition system should be used.

On vent and flare lines, consideration for drainage and flushing of low-lying pipe runs and the climate conditions should be reviewed to prevent potential freezing of water condensate in the lines. Flare lines should have a suitable flame detonation protection system (e.g., flame arrestors).

A.4.4.4 Commissioning

An auditable commissioning record or checklist should be used to show that all steps have been taken to confirm that the MPD system has been rigged up as per the approved P&IDs, and in the predefined approved location.

This record or checklist should document that all piping, electrical, mechanical, and instrumentation has been tested, functioned, and witnessed. This should include control system performance testing.

The capability of the MPD system to precisely control surface back-pressure should be verified up to the surface equipment pressure limit (considering a safety factor).

A.4.5 Determination of Safe Operating Limits

A.4.5.1 General

To enable planning and safe execution of MPD influx management, it is imperative that limits of the primary barrier envelope shall be established, understood, and communicated appropriately. These safe operating limits for influx management can be represented within an MPD operations matrix. The influx management envelope (IME) provides an alternative means of communicating the primary barrier limits.

Several methods are available to define the safe operating limits for MPD influx management based on kick tolerance concepts. Typically, the influx volume and intensity are analyzed and the resulting peak pressures and flow rates are compared to appropriate primary barrier limits. Specifically, peak pressures and flow rates occurring either during control or circulation of an influx are compared against surface equipment pressure limits, formation pressure limits, and surface equipment liquid and gas flow rate limits.

A.4.5.2 Standpipe Pressure Relief Setpoints

Consider standpipe pressure relief set points with respect to influx management and circulation. The PRV set point and automatic pump trip pressure should be set by the driller.

These set points are often set lower than the pressure rating on standpipe and are often what limits SBP if circulating at drilling rate. Set points should be set high enough to not limit surface pressures during influx control and testing of the system.

A.4.5.3 Surface Equipment Pressure Limit

The surface equipment pressure limit is dictated by the lowest pressure rating of all surface equipment in the primary barrier, for example:

— RCD and surface MPD system components;

— riser system components (for subsea BOP applications);

— PRV set points.

In conventional well control theory for gas influx, the peak pressure observed at surface should occur when the top of the influx reaches surface. During MPD influx management, the observed maximum surface pressure could occur during initial control (as opposed to during circulation), or when the influx reaches changes in annular cross section geometry.

A.4.5.4 Formation Pressure Limit

The formation pressure limit represents the maximum pressure that can be applied at the open formation's weakest point. This limit, after considering an appropriate safety factor, provides the peak wellbore pressure observed/that can be applied during either initial control or constant bottom-hole pressure circulation of an influx.

A.4.5.5 Surface Flow Rate Limits

The surface flow rate limits represent the primary barrier envelope capacity with regards to peak liquid and gas flow rates expected during the MPD influx management process.

The surface flow rate limits are dictated by the liquid and gas flow rate limits of the surface equipment—typically the liquid and gas flow rate limits of the mud gas separator and its inlet and outlet piping.

A.4.5.6 Operational Influx Volume Limit

The maximum influx volume limit should be defined on a case-by-case basis through analysis and calculations. Some MPD users are not comfortable with the smaller volume sizes that the MPD system is capable of handling; for these cases, an operational influx volume limit may be set at volume below the calculated maximum volume limit.

A.4.5.7 Overview of Influx Control Methods and Potential Limitations

MPD influx response involves increasing the EMW/ECD within the wellbore to regain an overbalanced condition. This is accomplished through the application of additional surface pressure using the MPD choke. When complete, though formation fluids are in the wellbore, the primary barrier has been reinstated and no additional influx is occurring.

MPD influx control can be accomplished by different operational methods. The addition of SBP can be done using the following methods until the flow in and flow out are equal:

a) operator increasing SBP by manually adjusting the choke position;

b) operator increasing SBP set point in stages;

c) automated system closing the choke.

Once one of the above methods has resulted in arresting the influx, a safety margin (additional SBP) can be applied. The method selected and the amount of safety margin to apply should be determined and communicated to the choke operator and the driller in advance.

When the influx is arrested, the crews shall ascertain the total influx volume taken. The volume gained and the resulting SBP are the parameters used to determine if the influx is within the system safe operation limits and can be circulated out using the MPD system or is beyond the system capability and will require transition to secondary well barrier. Please refer to one of the methodologies in A.7 for details in determining the tolerable influx volumes. The rig crew shall reference the limits as defined in the IME or MPD operating matrix.

The mud type in use can impact the duration required to arrest the influx. Oil and synthetic muds are more compressible and can therefore add complexity and time to the process, as the response will be slightly delayed. Understanding of the mud system and the compressibility effects will be beneficial to the rig-based team during this process. This understanding or “feel” can be gained by the rig team through drills; see A.5.2.

For the cases where the influx cannot be suppressed by increasing SBP due to MPD equipment limitation, the control of the influx shall be transferred to the secondary well barrier.

A.4.5.8 Influx Management Envelope

A.4.5.8.1 General

The IME is used to define the safe operating limits in case of incidental influxes during MPD operations. Based on kick tolerance concepts, the relationship between influx volume and intensity is used to graphically represent the primary well control barrier limits. The IME methodology illustrated in this document may be used to graphically represent safe influx management limits to users; however, operators may use a different methodology to compute and represent safe influx management limits.

A combination of regions within the influx volume versus post-influx surface pressure graph depict conditions in which an influx can be safely removed from the wellbore using the MPD equipment or should be contained with the secondary well control barrier (the BOPs) by conventionally shutting-in the well. Thus, the IME graphically represents acceptable limits for MPD influx circulation using the same premise as the industry standard MPD operations matrix.

Further clarity is achieved by applying the IME, rather than the MPD operations matrix, by virtue of more definition in influx volume and intensity combinations being applied to outline various regions within the acceptable influx control limits. Such regions include defining clearly whether a weak point at the formation is at risk of being fractured, whether the ability to conventionally shut-in at any point during influx control without incurring further influx exists, and whether pump rate may be maintained at drilling rate or needs to be decreased at some point during removal of the influx from the wellbore.

Critical to applying an IME correctly is the understanding that an influx scenario is evaluated at the moment after the influx has been stopped, the surface pressure safety margin applied, and the decision of whether to commence with influx control or to conventionally shut-in is ready to be made. At this point, the location on the IME, based on estimated influx volume and current surface back-pressure (post-influx surface pressure), is identified and the plan forward decided.

Once the decision to perform influx control has been made and influx circulation is initiated, the IME is no longer valid. That is, tracking surface pressure and/or estimated expanded influx volume on to different regions of the IME during influx removal is NOT valid and is an erroneous use of the IME. The IME is only valid at the moment constant bottom-hole pressure circulation of the influx is about to commence, with the suggested region having been generated from predictive analysis.

A generalized IME is shown in Figure A.1, in which color coding of the various IME regions assists identification of the appropriate response for managing an influx. The IME color regions are proposed as follows.

a) The yellow area defines an operational region where a detected and controlled influx can be circulated to surface within the capacity of the primary wellbore barrier at full drilling pump rate, i.e., full MPD dynamic influx control.

b) The orange area defines conditions for which an influx may be removed from the wellbore with the MPD equipment. However, at some point during circulation of the influx, the pump rate is decreased to a predetermined rate to ensure liquid or gas flow rate limits are not exceeded during removal of the influx, i.e., MPD dynamic influx control with reduced circulation rate.

c) The red area defines conditions in which it is deemed that some limit(s) of the primary barrier may have been exceeded or may be exceeded during the circulation process, indicating that the well should be secured with the secondary barrier envelope, i.e., conventional well control.

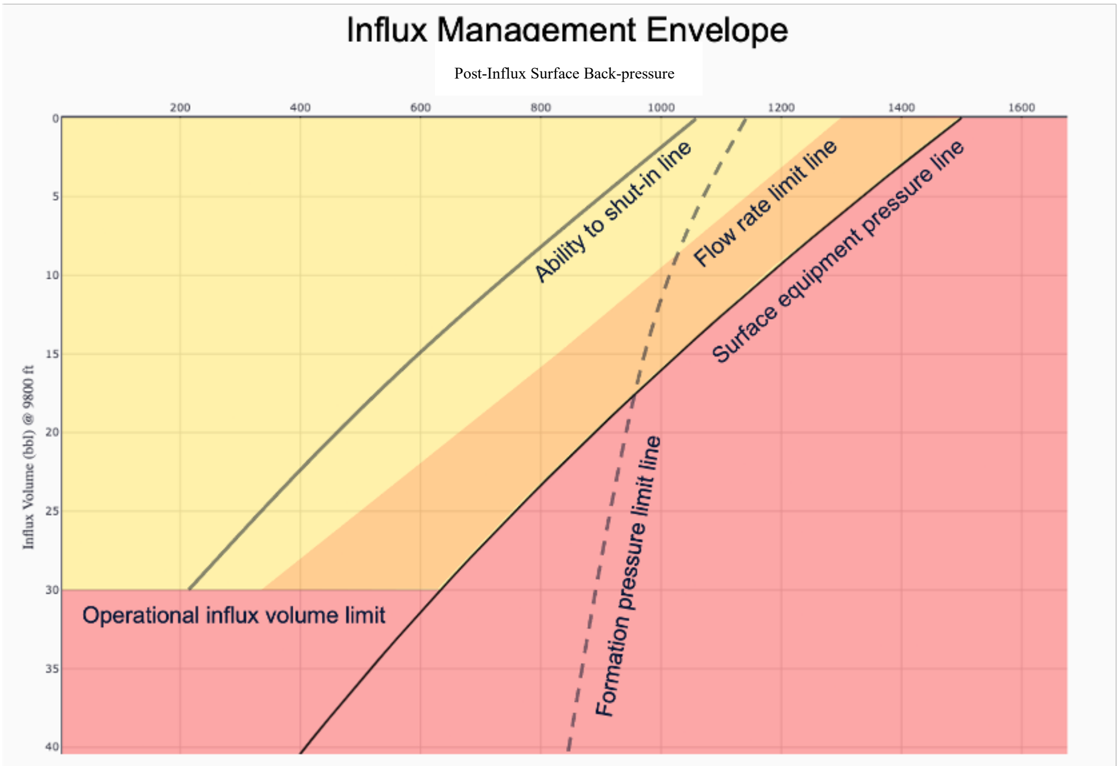


Figure A.1—Generalized Influx Management Envelope

A.4.5.8.2 IME Limit Lines

Limit lines are plotted on the IME and define combinations of influx volume and post-influx surface pressure for which it is anticipated that the associated limit may have been exceeded or is likely to be exceeded during circulation of the influx. The color regions within the IME, as described above, are bounded by IME limit lines as appropriate for a given project. However, limit lines may also be considered informational, whereby the curve may represent scenarios that exceed a given limit but do not constitute a different color region on the IME.

In general, whether a specific limit line defines transition between color regions within the IME (i.e., a hard limit) or if the limit is to be considered informational is project dependent with the approach being decided amongst the project team. As an example, the transition to the red IME region may be bounded by a combination of the surface pressure limit line, the weak point limit line, and the maximum volume limit, as shown in Figure A.1. However, the surface pressure limit line with the ability to shut-in without incurring further influx may be considered informational, providing a useful indication that more advanced procedures may be required in the event of shutting-in conventionally during dynamic influx control.

A.4.5.8.3 Calculating IME Limit Lines

Limit lines are constructed by analyzing combinations of influx volume and intensity such that during control or subsequent removal of the influx, the peak value of the given parameter is equal to the associated limit. In this way, each limit line can be constructed independently from one another, creating a clear depiction of the effect on subsequent dynamic influx control decision-making by each limit.

Construction of the IME limit lines may be calculated by any appropriate method.

The IME shall include hard limits in accordance with the MPD system being used and wellbore conditions. The following pressure and flow limits should be considered when defining hard limits (see Figure A.1).

a) Surface equipment pressure line—this will generally be considered a hard limit, indicating that for combination of influx volume and post-influx surface back-pressure which are located to the right of this line should be considered as an influx scenario where conventional well control is required.

b) Surface equipment pressure limit line with the ability to shut-in—this may or may not be considered a hard limit. This limit line is used to indicate that BHP may not be constantly maintained during hand-over to the secondary barrier to control the well during dynamic influx control, unless procedures allow increasing surface pressure beyond the surface equipment pressure limit used for creation of the IME as the pumps are shut-down.

c) Formation pressure limit line—this may or may not be considered a hard limit and is used to indicate that for combinations of influx volume and post-influx surface pressure which are located to the right of this line there may be high risk of breaking down the formation.

d) Flow rate limit lines—rather than constructing specific limit lines for surface liquid and gas flow rates, if it is expected at the drilling pump rate that liquid or gas rate limits can be exceeded during removal of an influx, then the yellow region becomes orange, indicating the pump rate be reduced to a predetermined value prior to lining up to the separator. This may be calculated from a worst-case scenario.

A.4.5.8.4 Updating an Influx Management Envelope

For each section to be drilled in the well, a specific IME (or any alternative representation method used) should be generated for the planned TD, with the established pressure limits to define when/where the yellow, orange, and red zones are applicable and agreed between all the parties involved.

A.4.5.9 Relationship between MPD Operations Matrix and Influx Management Envelope

The MPD operations matrix and the IME calculations determine how an influx can safely be circulated out of the well; the matrix is a table representation, and the IME is a graphical representation. Both should be based on the same calculations to determine the limits of influx, which can be based on a multiphase model simulator or a suitable influx calculation method. The results of these calculations are the technical limits for the MPD influx circulation and can be reduced as desired.

A.4.6 Overview of Different Circulation Methods

A.4.6.1 General

MPD systems allow for different ways to circulate an influx through the wellbore. Interventions with a subsea BOP have more influx circulation possibilities than an intervention with a surface BOP. The selection of any circulation method shall consider the impact on the equipment and procedures involved.

The decision to proceed to do the circulation phase of the influx with the MPD system shall be backed by a prejob analysis to define the pressure limits when circulating with the MPD system.

The following list is not restrictive; different methods should be fully discussed and reviewed:

a) circulate with open BOP (MPD dynamic influx control/circulation);

b) circulate through secondary flowline with closed annular (surface stack);

c) circulate below the BOP and isolate the well with the BOP;

d) circulate above the BOP and Isolate the well with the BOP;

e) conventional well control with MPD assistance (assisted shut-in).

Details on these circulation methods are included in Section 5.

A.4.6.2 Operating Procedures Specific to Influx Circulation

If the MPD system is planned to be used for influx removal from the wellbore, additional procedures will be required to clearly address influx management operations. These procedures may not have been generated for the basic use of MPD and will specify the use of the system to route formation fluids, including hydrocarbons, through parts of the wellbore not usually planned for influx removal (e.g., marine riser in deep water operations) and through the MPD system. A detailed review of the changes to the conventional MPD operation should be carried out with the objective of identifying the impacts of these changes. All involved parties shall know the influx procedures and specific roles for each party of the operation.

The operating limits and decision points in the procedures are dependent on the operational envelope identified in the planning phase. Contingency procedures should also be identified in case the operation deviates from the predefined operating limits or in case of equipment failures.

These procedures should be developed with and agreed upon by the operator, drilling contractor, and MPD service providers. Since MPD influx management techniques and procedures can change the standard operations during secondary well control events, these procedures shall be either incorporated or referenced in the operator's and drilling contractor's bridging documents.

Procedures can be classified into three separate modes:

— detection of influx;

— control of influx;

— circulation of influx.

The complete set of procedures should address all three modes.

The following are topics that should be included in the new procmdures required for influx circulation using the primary barrier:

a) Influx circulation methodology:

  — circulation to surface using MPD equipment;

  — circulation to shoe/BOPs using the MPD system, then conversion to conventional well control circulation (include shut-in of BOPs);

  — conventional well control circulation;

    — line up of flow paths;

    — decision tree for transitioning from MPD to secondary well control system during circulation (during circulation or while controlling the influx);

b) Contingency procedures:

- equipment failure (while circulating a kick or shutting the well);
- control system failure (while circulating, individual components);
- loss event (while circulating);
- influx while cementing (check cementing with MPD operations).

A.5 Training and Drills

A.5.1 Training

Where MPD influx management is planned as part of an MPD operation, individual roles and responsibilities will be different to conventional well control. The training program for key personnel should include MPD influx management techniques and procedures.

If simulator training is being held for MPD operations, then influx management should be included in the scenarios to simulate detection, control, and circulation of the influx using MPD techniques.

A.5.2 Drills

Where MPD influx management is planned as part of an MPD operation, additional drills to those defined in 9.5 may be considered as shown in Table A.1. It may be possible to perform some drills offline.

Table A.1 — Crew Drills

Type	Frequency	Objective	Comment
Simulated influx	Once prior to starting MPD operations with crew on tour/shift.	Demonstrate ability to detect an influx. Practice controlling an influx using MPD influx control procedures. Practice determining influx size based upon IME or matrix (yellow or red zone) and appropriate course of action.	Before drilling out of the last casing prior to MPD operation. Consider high-pressure cased hole test of choke controller.
MPD-assisted shut-in	Once prior to starting MPD operations with crew on tour/shift.	Practice shutting in the well with the BOP while using MPD assist to apply SBP.	Before drilling out of the last casing prior to MPD operation.
NOTE Due to operational constraints it is unlikely that all crews can be included in physical drills at the wellsite. Drills may be supplemented by training to cover all crews.			

A.6 Execution Considerations

A.6.1 Influx Detection

When using MPD for MPD influx management, the MPD system shall have reliable means of detecting an influx and quantifying its size. The resolution of influx detection and accuracy of quantification of influx volume shall be adequate for planned operations.

The MPD system shall include return flow measurements, such as a flow paddle, combined with PVT or a Coriolis meter. More accurate and redundant measurements of flow rate enable earlier influx detection and more accurate and reliable quantification of the influx volume taken.

Uncertainties in volume and flow measurements shall be accounted for when quantifying the size of an influx volume taken. Oil-based mud (OBM) might cause influx volume reduction due to formation fluids entering into solution in the mud. OBM can pose a difficulty to confirmation of the control, a longer period of time might be needed to monitor the well reaction. Large-volume systems can present additional challenges in influx volume quantification, as fluid compressibility can mask the real volume of the influx taken. Thermal effects can also have impact on the volume calculation.

A.6.2 Influx Control

A.6.2.1 General

The objective of MPD influx control is to reestablish overbalance by applying surface back-pressure. The recommended approach is to perform influx control while continuing circulation of the rig pumps (dynamic influx control). Alternatively, influx control can be done by stopping circulation and shutting in on the MPD system or shutting in conventionally with MPD assistance.

There are different techniques to apply SBP control, including increasing surface back-pressure until the influx is terminated.

A.6.2.2 MPD Dynamic Influx Control

To perform dynamic influx control, the MPD system shall have return flow measurements capable of confirming influx control while circulating and controlling the surface back-pressure precisely during changing compressibility caused by the influx.

Once an influx is detected, the recommended procedure is to pull off bottom and increase the surface back-pressure while maintaining normal circulation rate. The applied surface pressure is then increased until the influx is stopped and the influx is contained. If the predetermined surface equipment pressure limit is reached (see A.4.5.3), the well shall be handed over to secondary well control and MPD system isolated.

NOTE 1 Pulling off bottom or moving pipe during the initial reaction to an influx can change the well volume, and such changes can have an impact on surface back-pressure values.

Influx control is achieved by confirming that the standpipe pressure is constant and circulation is steady with a pump flow rate equal to the return flow rate (until the expansion phase). These are sufficient conditions to confirm that overbalance is established with a constant influx volume contained in annulus while circulating. If the above steady conditions cannot be confirmed, it is recommended to proceed with static influx control.

NOTE 2 Different MPD systems have different methods to determine when an influx has been suitably controlled. One popular method is to compare the flow rate into the well and the flow rate out; when the flow out and flow into the well are equal, it can be assumed that there is no further influx from the formation.

Influx volume is determined based on active pit measurements or accumulated flow rate measurements. See A.6.1 for recommendations on influx volume.

A.6.2.3 MPD Static Influx Control

If dynamic influx control is not possible or confirmation of influx control while circulating is unsuccessful, the MPD system can be used for static influx control.

The initial step of the procedure is identical to dynamic influx control; the surface back-pressure is increased to stop the influx while circulating off bottom, causing return flow (out) to equal pump flow (in). Next, rig pumps are shut down while the surface back-pressure is increased to maintain bottom-hole pressure constant, eventually shutting in on the MPD chokes. Isolate the MPD system if the predetermined surface equipment pressure limit is reached (see A.4.5.3) by closing the BOPs. Then the influx shall be circulated out of the well using conventional well control methods.

The time to turn down the rig's pumps aligned to the string should be minimized, as any delay displaces the influx further up the annulus and possibly above the BOP.

Influx control is confirmed when the surface back-pressure has stabilized.

Influx volume is determined based on active pit or flow rate measurements. See A.6.1 for recommendations on influx volume.

A.6.3 Influx Circulation

A.6.3.1 General

If the influx volume and intensity that has been determined during the influx control falls inside the safe operational limits, it can be circulated out using the MPD system. If not, a predefined procedure approved by the operator and drilling contractor shall be implemented for how the well shall be handed over to secondary well control and the MPD system is isolated.

To perform MPD influx management, the MPD system capabilities of controlling and maintaining constant BHP over the full range of pressures and flow rates expected while circulating out an influx shall be verified. If the MPD system is not capable of controlling the well during influx circulation, the operation shall revert to the conventional well control (secondary barrier).

With full MPD influx management, all steps from the influx management (detection, control, and circulation), are handled through the MPD system. Optionally, influx circulation can be done partially conventional. A.6.3.2 through A.6.3.5 outline alternative methods for circulating out a contained influx volume.

A.6.3.2 Circulating with Open BOP (MPD Dynamic Influx Control/Circulation)

Having performed a dynamic influx control, the influx can be circulated without interrupting pump circulation. If a static influx control has been performed, pump circulation can be resumed.

As the BOP is not closed, it is possible to move and rotate the string, reducing the chances of well cleaning problems and stuck pipe while circulating an influx out of the well.

Circulating the influx at normal flow rates may enable PWD readings to be transmitted during circulation to provide accurate monitoring of bottom-hole pressure during the operation.

As the flow rate for this method may be higher than the flow rate from conventional well control techniques, all the equipment and piping involved, including the MGS, shall be capable of handling the gas and liquid flow rates expected.

The recommended method to circulate an influx with the MPD system is the driller's method first circulation, in which a constant BHP is established and maintained by a constant standpipe pressure (SPP). This is either done automatically by the MPD system or by manually manipulating chokes.

Drilling ahead while circulating an influx is not recommended.

The criteria that should be constantly monitored during influx circulation are as follows:

a) maximum surface back-pressure that is or will be applied when the influx (if gas) reaches the surface and expands to its fullest potential.

b) the volume and flow rate of gas and mud entering the MGS against the MGS capacity.

c) real-time pressure data should be available while the influx is circulated out.

To avoid exceeding the mud gas separator limits, circulation rates can be reduced (maintaining constant BHP) with influx nearing surface. If such a case is anticipated, strategies and procedures should be put in place to avoid increasing the SBP beyond the surface equipment and PRV limits.

The limiting factor from the SBP perspective for influx circulation could be the event that the well will have to be closed on MPD chokes due to pump failure with gas at or nearing surface. The well can be shut-in on BOP's reverting to secondary well control if there is a chance that the surface equipment pressure limits are exceeded.

As the risk exists that the operation may have to be stopped with gas at or near surface due to a pump or choke failure, a developed procedure shall be in place to monitor for gas migration and response.

A.6.3.3 Circulating below the BOP and Isolating the Well with the BOP

This method is specific for subsea BOP's. The goal is to control the influx using the MPD system and circulate the influx up the well using the MPD system maintaining a constant SPP. Prior to the top of the influx reaching the BOPs, the pumps are ramped down. During pump ramp down, the choke is manipulated to maintain constant bottom-hole pressure.

When determining at what point in the circulation to shut down the downhole pumps and transition to conventional well control, account for some gas movement and make this transition at a conservative depth, especially, if any pumps off time occurred during the circulation.

A.6.3.4 Circulating above the BOP and Isolating the Well with the BOP

This method is specific for subsea BOP's. The goal is to control the influx using the MPD system and circulate the influx up the well using the MPD system maintaining a constant SPP. After the bottom of the influx passing the BOPs, the pumps are ramped down. During pump ramp down, the choke is manipulated to maintain constant bottom-hole pressure. The well is secured and monitored through the kill and choke lines surface pressure.

The influx in the riser is similar to a gas-in-riser situation. However, the open hole is isolated and the pressure source removed from the system as the BOP is closed. Also, isolating the wellbore allows for a reduction or increase in the back-pressure without impacting BHP, thus broadening the pressure control range for circulating the influx out of the riser. With the MPD system there is the ability to manage back-pressure and control the expansion of the influx inside the riser. The use of additional back-pressure can reduce the gas expansion rate near surface. As the influx no longer impacts the hydrostatic pressure inside the well, the circulation of the influx out will be limited only by surface flow capacity after the choke.

Attention should be given to the potential to have a higher pressure above the BOP than in the wellbore.

A.6.3.5 Conventional Well Control with MPD Assistance (Assisted Shut-in)

After having performed static influx control with the influx volume contained by shutting in on the MPD chokes, conventional well control techniques can then be applied with a smaller influx volume in the wellbore.

A.7 Tolerable Influx Volume Calculation Methodology

A.7.1 General

Engineered methods to calculating the tolerable volume show that it is in fact dependent on numerous, changing drilling variables. Many examples have shown that reliance on a single value for this volume can be overly conservative and, in some cases, erroneous, and an engineered approach desirable.

A sample list of these variables are as follows:

a) initial influx volume at the bottom of the hole;

b) resultant surface back-pressure when the influx reaches surface;

c) surface back-pressure immediately after the influx has been arrested dynamically;

d) annular friction pressure of drilling fluid immediately after stopping the influx;

e) annular friction pressure of drilling fluid once the influx reaches surface;

f) casing design kick tolerance;

g) cross-sectional area between the BHA/drill pipe and the wellbore/casing/riser;

h) bottom-hole circulating temperature;

i) surface flowing temperature;

j) drilling mud density;

k) influx density;

l) wellbore inclination.

Understanding the methodology to calculating a tolerable influx volume requires the establishment of the premise that, at a specific depth, an influx has been detected and arrested using the MPD equipment (i.e., surface back-pressure has been increased), such that no further formation fluids are entering the wellbore.

To determine the safe circulation limits with respect to pressure, the pre-influx and post-influx circulation states should be examined. Effectively, the calculation is backwards and top-down – identifying what is the maximum allowable expanded surface influx size that will not overpressure the primary barrier limits. The next step is to calculate what that influx size would be at the bottom of the hole, at the time of suppression or control when the decision on the method of influx circulation is determined. The controlled bottom-hole influx volume is the guiding variable for primary barrier influx circulation; bottom-hole influx volumes lower than the calculated limit could be circulated within the primary barrier, while volumes exceeding it will involve the use of secondary barrier equipment.

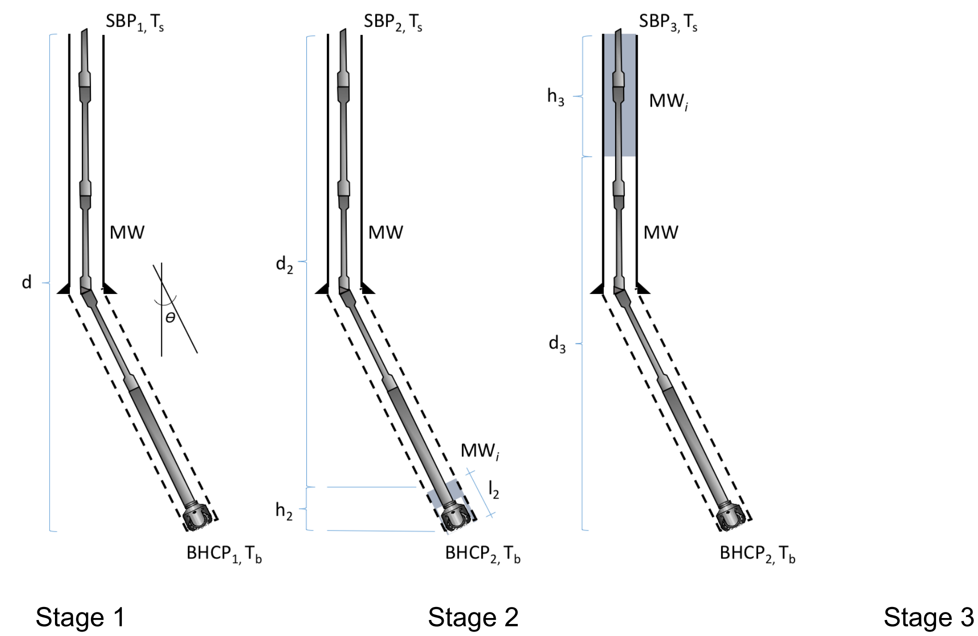
NOTE A conservative assumption is made that the influx is indeed a gas, although it is not possible to determine the state of an influx at the time of detection. A liquid-based influx will not expand as it reaches surfaces and will therefore exert a lower pressure.

A.7.2 Overview of the Method

A.7.2.1 General

An example well in Figure A.2 shows the three stages of the MPD influx management along with the key variables. Sections A.7.2.2 through A.7.2.4 describe one of the possible methodologies of calculating the operational limits. The following method presents a simplified overview of the calculation of the IME limits, based on basic single bubble principles.

When these additional criteria are introduced into the IME calculation, the maximum influx volume (and pressures) can be modeled, establishing the limits in the IME and providing guidance on the decision to revert to secondary well control.



Key

Stage 1: no influx.

Stage 2: influx arrested; trapped volume at the bottom of the hole.

Stage 3: influx at surface.

Figure A.2—Stages of MPD Influx Management

A.7.2.2 Drilling Ahead—No Influx

A hypothetical well of depth d (TVD) and inclination θ is drilled using SBP MPD with a mud weight MW. The flowing bottom-hole temperature is T_b and the return temperature at surface is T_s. The applied surface back-pressure is SBP_1 and bottom-hole circulating pressure is $BHCP_1$ when an influx is detected.

A.7.2.3 Influx Detected and Controlled with MPD Choke

The bit is picked up off bottom and the influx is controlled by the application of increased surface back-pressure, resulting in an increase in bottom-hole circulation pressure (BHCP). This is done dynamically with the primary barrier equipment only. At the point when the influx is under control and the well is again overbalanced, the operational parameters are as follows:

a) surface back-pressure is SBP_2 (greater than SBP_1);

b) post-influx BHCP is $BHCP_2$ (greater than $BHCP_1$);

c) height of the influx at the bottom of the hole is h_2;

d) the length of the influx at the bottom of the hole is l_2;

e) mud weight of the influx is MW_i;

f) height of the mud column is d_2 with mud weight MW.

This post-influx state, with the influx at the bottom of the hole is depicted in Stage 2.

A.7.2.4 Influx Reaches Surface

Circulation of the influx requires $BHCP_2$ be maintained constant to ensure that no further fluid ingress occurs. This is accomplished by modulating the choke during circulation, maintaining drill pipe pressure constant.

When the influx reaches surface, the operational parameters are as follows:

a) surface back-pressure is SBP_3 (greater than SBP_2);

b) post-influx BHCP is $BHCP_2$, the same as (2);

c) height of the influx at surface is h_3;

d) mud weight of the influx is MW_i;

e) height of the mud column is d_3 with mud weight MW.

The objective is to determine the post-arrest (or initial on bottom) influx volume (V_2) that can be circulated with the MPD equipment. The key to performing this calculation is the fact that $BHCP_2$ is the same in Stage 2 and Stage 3. This allows a link to be established between the surface variables SBP_3 and V_3 (influx volume at surface) and the on-bottom influx volume.

A.7.3 Setting the Surface Back-pressure Limit

When the variable SBP_3 is set to a user-defined surface pressure limit of the primary barrier (RCD operational pressure limit, riser pressure limit, etc.), the calculation yields an on-bottom influx volume (V_2) that can be safely circulated (with respect to pressure only) without stopping the pumps and shutting in (i.e., conventional well control operations).

This pressure should not be set arbitrarily; the operational specifications and limitations of the primary barrier pressure-containing equipment should be scrutinized prior to determining the final value. If the RCD is identified as the governing pressure criterion, choosing the API 16RCD dynamic pressure rating may not be advisable, as the published pressure ratings reflect idealized conditions. Engagement of the service provider is highly recommended, as fit-for-purpose testing prior to drilling operations may be recommended to confidently determine these values.

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