

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

API RECOMMENDED PRACTICE 92S
FIRST EDITION, SEPTEMBER 2018

ADDENDUM 1, APRIL 2023



American
Petroleum
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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) H₂S 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 string configurations, and drilling parameters.
- r) H₂S 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, H₂S, CO₂.
- 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.

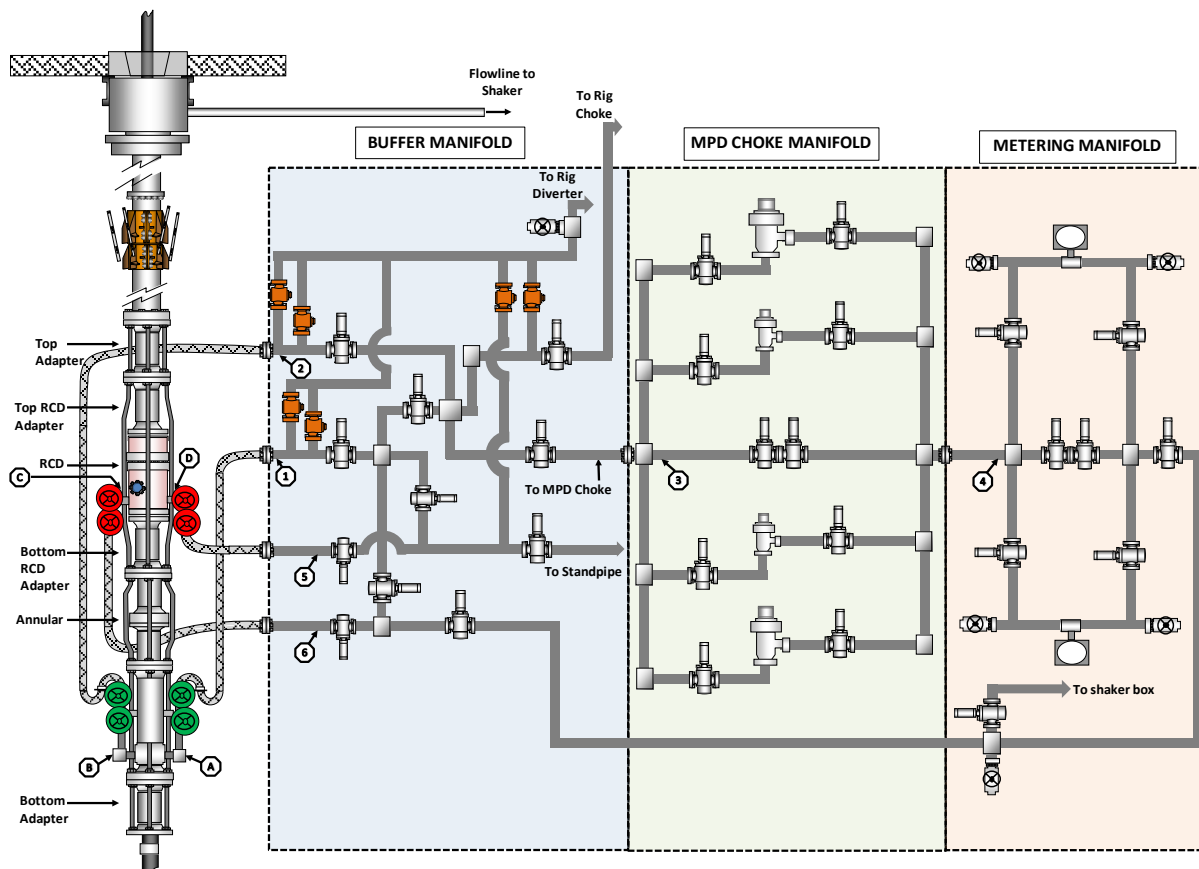


Figure 1—Simplified Managed Pressure Drilling P&ID Diagram

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;