GUIDE FOR CLASSIFICATION AND CERTIFICATION OF

MANAGED PRESSURE DRILLING SYSTEMS

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American Bureau of Shipping
Incorporated by Act of Legislature of
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Updates

May 2018 consolidation includes:

- September 2017 version plus Notice No. 1

Foreword *(1 May 2018)*

Managed Pressure Drilling (MPD) techniques have proven to be cost-effective, reliable, and safe when drilling difficult onshore wells as well as when drilling from mobile offshore drilling units (MODU) with a surface BOP. MPD is now widely being used as an enabling method in drilling increasingly complex and challenging offshore wells from MODUs with subsea BOPs.

As the leading global provider of offshore classification services, ABS is deeply involved in the safe and reliable use of MPD technology in global shallow-water and floating rig applications through design verification and validation. ABS has worked closely with the drilling industry to develop this Guide that specifies the classification and certification requirements for MPD systems, subsystems and equipment. This Guide is intended to be used in conjunction with the ABS *Guide for the Classification of Drilling Systems* (*CDS Guide*), other applicable ABS Rules and Guides, codes and standards as referenced therein, and applicable national regulations.

For ABS classed drilling units that are in compliance with this Guide, the optional **ABS MPD™** and **ABS MPD-Ready™** class notations are offered. These notations are offered to drilling units that may or may not be classed with any of ABS' **CDS** notations and sub-notations for the associated drilling systems.

ABS also offers certification services for MPD systems, subsystems, equipment and/or components provided that the applicable requirements in this Guide are fulfilled. Certification can be provided for drilling units classed with ABS as well as for non-ABS classed units.

The May 2018 update introduces the notations **ABS MPD™** and **ABS MPD-Ready™**, which are pending trademark.

This Guide becomes effective on the first day of the month of publication.

Users are advised to check periodically on the ABS website www.eagle.org to verify that this version of this Guide is the most current.

We welcome your feedback. Comments or suggestions can be sent electronically by email to rsd@eagle.org.

GUIDE FOR CLASSIFICATION AND CERTIFICATION OF

MANAGED PRESSURE DRILLING SYSTEMS

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SECTION 1 General

1 General *(1 May 2018)*

The general requirements for conditions of Classification and Certification are contained in the ABS *Rules for Conditions of Classification – Offshore Units and Structures (Part 1)*. Additional requirements specific to managed pressure drilling (MPD) systems are contained in this Guide.

This Guide is intended to be used in conjunction with the ABS *Guide for the Classification of Drilling Systems* (*CDS Guide*). The requirements contained herein and the referenced requirements from the *CDS Guide* are both to be met for classification and certification of MPD systems.

For ABS classed drilling units that are in compliance with this Guide, the optional **ABS MPD** and **ABS MPD-Ready** class notations are offered. These notations are offered to drilling units that may or may not be classed with any of ABS' **CDS** notations and sub-notations for the associated drilling systems.

ABS also offers certification services for MPD systems, subsystems, equipment and/or components provided that the applicable requirements in this Guide are fulfilled. Certification can be provided for drilling units classed with ABS as well as for non-ABS classed units.

3 Scope

The focus of this Guide is on MPD systems utilizing a Rotating Control Device (RCD) and a surface choke system to create surface back-pressure, and those that maintain a Controlled Mud Level (CML). Section 3, Table 1, lists the MPD systems, subsystems and equipment that may be classed/certified using this Guide. For subsystems and equipment of MPD systems not listed, the client is to contact the appropriate ABS technical office for guidance on the approval process.

5 Classification and Class Notations

(1 May 2018) Two optional class notations related to MPD systems (**ABS MPD** and **ABS MPD-Ready**) are available for ABS classed drilling units provided the classification requirements in Sections 2 and 3, as applicable, are complied with.

5.1 MPD Systems *(1 May 2018)*

Where classification of an installed MPD systems is requested by the Owner/Operator, the MPD system may be classed and distinguished in the ABS *Record* by the notation ✠ **ABS MPD**, where approved by the Committee for service under the specified design environmental conditions.

5.3 "ABS MPD-Ready" Systems *(1 May 2018)*

The notation ✠ **ABS MPD-Ready** is available where MPD operations are anticipated however operationally-essential MPD equipment is not physically present. "ABS MPD-Ready" means that a rig, usually a floating MODU, is pre-fitted with provisions (e.g., general piping and tie-in points pre-installed) to deploy a MPD system. When an MPD system is installed on an "ABS MPD-Ready" rig, the Record may be distinguished accordingly from "ABS MPD-Ready" to "ABS MPD", where classification of this system is requested by the Owner/Operator and thereafter approved by the Committee.

5.5 Systems Not Built Under Survey

The symbol "✠" (Maltese-Cross) signifies that the system was reviewed, built, installed and commissioned to the satisfaction of ABS. MPD systems, sub-systems, or equipment that have not been built under ABS survey, but which are submitted for Classification, will be subjected to special consideration. Where found satisfactory and thereafter approved by the Committee, they may be classed and distinguished in the Record by the notation described above, but the symbol "✠" signifying survey during construction will be omitted.

7 Certification

Upon request of the Owner/Operator or Designer/Manufacturer, and where permitted by the recognized Authority, ABS will issue Certificates for MPD systems, subsystems, equipment and/or components provided that the requirements in this Guide are fulfilled. Where authorized by a government agency and upon request of the Owner/Operator, ABS will survey and certify a classed MPD system or one intended to be classed for compliance with particular regulations of that government on their behalf.

Certification can be provided for drilling units classed with ABS as well as for non-ABS classed units. All the requirements in this Guide are applicable to certification except those in Subsection 3/7, "Survey after Commissioning".

9 Certification and Classification Process

(1 May 2018) Section 1, Figure 1 shows the typical process for ABS Certification of MPD systems, subsystems, equipment and components and the way forward to Classification of MPD systems. Section 3, Table 1 identifies the typical MPD systems, subsystems and equipment that are part of the ABS Classification/Certification process. For MPD systems, subsystems, equipment and/or components not listed, the designer/manufacturer is to contact the appropriate ABS Technical office for guidance on the approval process.

For the **ABS MPD-Ready** notation, the scope is only for the pre-fitted provisions on the rig, therefore, the process of "ABS Survey at Vendor's Plant" in Section 1, Figure 1 may not apply.

Detailed ABS Classification and Certification process for drilling systems, subsystem, equipment, and/or components is contained in Section 4 of the *CDS Guide.* A brief summary of the process is provided below.

9.1 Certification Process

i) Related MPD systems, subsystems, equipment and component drawings, calculations and documentation are required to be submitted to ABS by entities as listed in Subsection 1/19 to substantiate that the design of the systems, subsystems, equipment and/or components are in compliance with this Guide, and applicable codes or standards, as listed in this Guide.

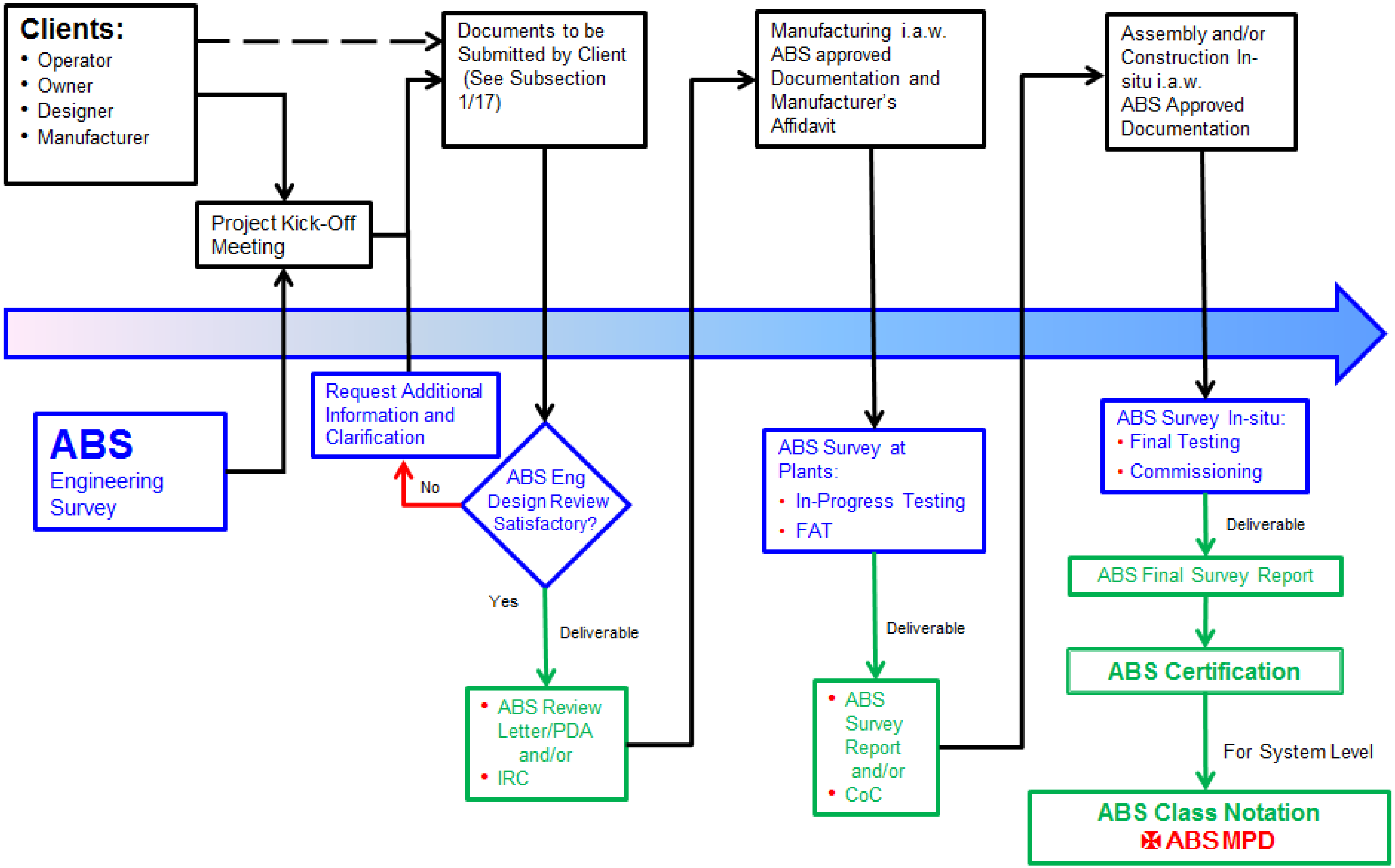
ii) Upon satisfactory completion of ABS review of design documents, ABS Engineers will issue an ABS review letter and/or an Independent Review Certificate (IRC), as specified in Section 3, Table 1. This letter or IRC, in conjunction with ABS-approved documentation, will be used and referenced during surveys.

iii) Upon satisfactory completion of survey, ABS Surveyors will issue appropriate survey reports and/or a Certificate of Conformity (CoC).

9.3 Classification Process

In addition to items *i)* through *iii)* above, and upon satisfactory completion of all of the required engineering design review and survey processes (inspection, testing, installation and commissioning), ABS may issue a Classification Certificate to the drilling unit, including the Class notation as listed in Subsection 1/5.

FIGURE 1
ABS Classification/Certification Process



Note: For "**ABS MPD-Ready**" Notation, "ABS Survey at Vendor's Plant" may not apply.

11 Applicable Codes and Standards

This Guide is intended for use in conjunction with codes and standards listed in this subsection, as well as those standards referred by related Sections/Subsections of *CDS Guide*.

ABS	Guide for the Classification of Drilling Systems (CDS Guide)
API RP 14C	Recommended Practice for Analysis, Design, Installation, and Testing of Basic Safety Systems for Offshore Production Platforms’
API RP 14E	Recommended Practice for Design and Installation of Offshore Products Platform Piping Systems
API RP 16Q	Recommended Practice for Design, Selection, Operation and Maintenance of Marine Drilling Riser Systems
API RP 17B	Recommended Practice for Flexible Pipe
API RP 92C	Controlled Mud Level Managed Pressure Drilling Operations
API RP 92M	Managed Pressure Drilling Operations with Surface Back-pressure
API RP 92P	Managed Pressure Drilling Operations – Pressurized Mud Cap Drilling with a Subsea Blowout Preventer
API RP 92S	Managed Pressure Drilling Operations – Surface Back-pressure with a Subsea Blowout Preventer
API Spec 16A	Specification for Drill-Through Equipment
API Spec 16C	Specification for Choke and Kill Equipment
API Spec 16D	Specification for Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment
API Spec 16F	Specification for Marine Drilling Riser
API Spec 16RCD	Specification for Drill-Through Equipment – Rotating Control Devices
API Spec 17K	Specification for Bonded Flexible Pipe
API Spec 6A	Specification for Wellhead and Christmas Tree Equipment
API Spec 7K	Specification for Drilling and Well Servicing Equipment
API Spec 7NRV	Specification for Drill String Non-return Valves
API STD 53	Standard for Blowout Prevention Equipment Systems
API TR 6AF1	Technical Report on Temperature Derating on API Flanges under Combination of Loading
API TR 6AF2	Technical Report on Capabilities of API Integral Flanges Under Combination of Loading – Phase II
IADC	Well Classification System for Underbalanced Operations and Managed Pressure Drilling
ISO 15156/NACE MR0175	Petroleum and Natural Gas Industries—Materials for use in H2S-Containing Environments in Oil and Gas Production

13 Alternatives

13.1 General

ABS is ready to consider alternative arrangements and designs which can be shown through either satisfactory service experience or a systematic analysis based on sound engineering principles, to meet the overall safety, serviceability, and design standards of the Rules and Guides.

13.3 Standards or Basis of Design

i) Designs complying with other national or international standards not listed in Subsection 1/11 will be subject to special considerations, on a case-by-case basis. When alternate design codes and standards are proposed, justifications may be achieved through equivalency, gap analysis, or appropriate risk analysis to demonstrate that the proposed alternate design codes and standards will provide a safety level which is acceptable to ABS.

ii) Designs based on manufacturer's standards may also be accepted. In such cases, complete details of the manufacturer's standards and engineering justifications are to be submitted for review. The manufacturer will be required to demonstrate by way of testing or analysis that their design criteria employed results in a level of safety consistent with that of the recognized standard or code of practice. ABS will consider the application of risk evaluations for alternatives or novel features for the basis of design in accordance with the procedures specified in Subsection 1/15.

15 New Technologies and Novel Concepts

MPD systems, subsystems, equipment and/or components which contain novel design features to which the provisions of this Guide are not directly applicable may be classed/certified when approved by ABS. This will be on the basis that this Guide, insofar as applicable, has been complied with and that special consideration has been given to these aspects based on the best information available at that time. Justifications for the new or novel features can be accomplished by applying Subsection 1/17.

17 Risk Evaluations for Alternative Arrangements and Novel Features

i) Risk evaluations for the justification of alternative arrangements or novel features may be applicable either to the MPD system as a whole, or to individual subsystems, equipment and/or components.

ii) ABS will consider the application of risk evaluations for alternative arrangements and novel features in the design of the MPD system, subsystems, equipment and/or components, verification surveys during construction, and surveys for maintenance of Class.

iii) When applied, risk assessment techniques are to demonstrate that alternative arrangements and/or novel features provide acceptable levels of safety in line with current offshore and marine industry practice.

iv) Portions of the MPD system or any of its subsystems, equipment and/or components not explicitly included in the risk evaluation submitted to ABS are to comply with any applicable part of the ABS Rules and Guides.

v) If any proposed alternative arrangement or novel feature affects any applicable requirements of flag or coastal State, it is the responsibility of the Owner/Operator to discuss with the applicable authorities the acceptance of alternatives based on risk evaluations.

The ABS *Guidance Notes on Review and Approval of Novel Concepts*, *ABS Guidance Notes on Qualifying New Technologies*, and ABS *Guide for Risk Evaluations for the Classification of Marine-Related Facilities* provide guidance to ABS clients on the preparation of a risk evaluation to demonstrate equivalency or acceptability for a proposed MPD system design.

19 Design Plans and Data

Typical plans and data that are required to be submitted are listed below.

i) The general arrangement of the MPD system, equipment plans, including all relevant risk assessment reports are to be provided in accordance with 2/7.1 of the *CDS Guide* for the MPD system showing its proposed arrangement and integration with the elements of a specific rig's existing drilling system.

ii) Revised documentation that outlines modifications to the existing drilling system/equipment to accommodate MPD (piping modification, structural modifications, fire and gas detection, hazardous area plan, etc.).

iii) Emergency and shutdown philosophy

iv) MPD operational procedures (to be used as reference for reviewing the risk assessment reports)

v) Piping and instrumentation diagrams (P&IDs) and/or process flow diagrams (PFDs) including valve numbering and representation of all MPD-related equipment (including PRVs) and flow paths for each MPD scenario being planned, or considered possible.

vi) MPD equipment pressure relief protection providing rating/capacity and sizing calculations in accordance with 2/1.5 of the *CDS Guide*. Take into consideration possible variable PRV practices during scheduled operations when the MASP varies.

vii) Riser management system changes required by the MPD system including but not limited to changes caused by different drilling fluid density within the riser, changed hoop stresses arising from MPD practices, changes in the riser tensioning requirements, additional weight and external dimensions of the MPD riser joint, current and wave forces added by subsea pumps (and umbilicals) for some MPD methods, and other MPD-created loads on the drilling riser system.

viii) Details for any prime movers such as motors.

ix) Design documentation for mechanical load-bearing components, as per 2/7.13 of the *CDS Guide*.

x) Design details for all electrical systems and equipment, as per 2/7.17 of the *CDS Guide*.

xi) Design details for all control system, as per 2/7.19 of the *CDS Guide*.

xii) Design details for all MPD manifolds, pressure vessels, and tanks, as per 2/7.21 of the *CDS Guide*.

xiii) Design details for rigid piping, valves, and fittings, as per 2/7.23 of the *CDS Guide*.

xiv) Design details for flexible lines refer to 2/7.25 of the *CDS Guide*. Documentation (such as material specification, test procedures and test results) verifying material compatibility of flexible line linings with all anticipated well fluid types is to be submitted.

xv) Prototype test data, as required by the applicable design code.

xvi) Manufacturing specifications, as per 2/7.27 of the *CDS Guide*.

xvii) Manufacturer's Affidavit of Compliance (MAC), as per 4/3.1.2 of the *CDS Guide*.

xviii) List of handling and running equipment for all MPD systems. Each item included on this list will include documentation that demonstrates a "fit-for-purpose" design. Also, each listed item will include details describing the load test that was performed for that particular item.

xix) NACE H_2S rating and compliance

xx) Deck load and stability compliance

xxi) Diagrams for electrical power and instrumentation wiring routing and tie-ins

xxii) The design calculations for the MGS system(s), including both upstream and downstream piping diameters, run lengths, and the numbers of turns, verifying that the piping is capable of delivering returns throughout all operations and variations in flow rate at acceptably low pressures.

xxiii) Calculations demonstrating that the flare or vent piping of MGS system provided is of sufficient diameter for total flow capacity, maximum flow rate, back-pressure generated, and fluid velocity (for erosion tendencies).

xxiv) Basis of design for RCD bearing assembly running tools.

xxv) Additionally, for CML-MPD:

a) Summary statement describing any additional electrical power supplies required for all components of CML-MPD equipment is to be included in the submittals.

b) Design specifications for subsea pump module in accordance with 2/15.1 of this Guide are to be submitted.

c) Details of back flushing the mud return line (MRL) including the frequency of flushing is to be submitted.

c) If a rig pump is to be used for back flushing of MRL, a flow diagram showing the alignment of piping, flexible lines, and valves is to be submitted.

21 Definitions

The following definitions are provided to clarify the use of certain terms used in this Guide:

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.

Circulation System. The complete flow path that the drilling fluid travels from the mud pits to the mud pump intake, down the drill pipe, exiting through the jets of the drill bit, and back up the annular spaces until it returns to the surface for processing and return to the mud pits.

Closed Circulation System. A drilling fluid system flow path which is not open to the atmosphere.

Continuous Circulation Method (CCM). An MPD technique used to maintain flow down the drill pipe while making a connection, thereby maintaining equivalent circulating density (ECD) and thus keeping a constant pressure profile in well annulus to prevent an influx of formation fluids or potential hole collapse due to instability.

Controlled Mud Level (CML). A variant of Dual Gradient Drilling (DGD) used only on floating rigs by placing a special pump in/on the drilling riser to vary the level of fluid in the drilling riser. The fluid level is adjusted up or down to control bottom-hole pressure and to compensate for variations in equivalent circulating density due to frictional pressure losses.

Dual Gradient Drilling (DGD). A drilling process that creates multiple pressure gradients to manage the annular pressure profile.

Equivalent Circulating Density (ECD). 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.

Floating Mud Cap Drilling (FMCD). A drilling technique used to drill without returns while sacrificial fluid is continuously pumped down drill string and the annulus to avoid all possibility of formation fluid migrating to the surface. Open-hole formation is taking all injected (sacrificial) fluid and drilled cuttings without surface pressure assistance.

Friction Management Method or *Annular Friction Management*. Systems allowing for continued circulation during drill pipe connections, thereby maintaining constant bottom hole pressure. This technique is also referred to as the CCM method in some publications.

Managed Pressure Drilling (MPD). An adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore. The objectives are to ascertain the down-hole pressure environmental limits and to manage the annular hydraulic pressure profile accordingly.

Mass Flow Meter. A measuring device that is capable of working with flow streams to measure the mass rate of flow and the density of the fluid stream (e.g., Coriolis Meter).

MPD Annular. A device installed in the drilling riser below the RCD to make possible removing and replacing a worn RCD sealing/bearing element while back-pressure is being applied. MPD annular may be used to isolate the RCD during emergencies such as a gas in riser event.

Mud Cap Drilling (MCD). A drilling process that involves maintaining a mud level in the annulus below the surface for hole stability and well control purposes, and no surface back-pressure. In MCD, there are no flow returns to the surface while maintaining mud column on the annular side. There exists several MCD variations, such as PMCD, FMCD etc. MCD is an umbrella term used for FMCD and PMCD.

Pressure-relief Valve (PRV). A flow-control device installed as part of the circulating system able to open and shut in response to operating conditions in order to maintain preset limits for pressure applied to parts of the circulating system to prevent over pressurization.

Pressurized Mud Cap Drilling (PMCD). A drilling technique used to drill without returns while balancing a full annular fluid column by using a Light Annular Mud (LAM) cap maintained above an open-hole formation that is taking all injected (sacrificial) fluid and drilled cuttings assisted by surface pressure. The LAM density is chosen based on ability to make LAM and the desired surface pressure that can be maintained and observed. Periodically injecting more of the same fluid into the annulus provides a means to control the surface back-pressure within the operating limits of the RCD and/or riser system.

Primary Barrier. Phrase used to describe the first well barrier that prevents flow from a source.

Return Flow Control (RFC). MPD technique which diverts returned fluid flow away from the rig floor in order to handle any formation fluid influx, thereby avoiding closing of a BOP, with the subsequent well control steps that are customarily required. RFC is drilling with a closed annulus return system (RCD) immediately under the rig floor for complete assurance of the total diversion of any rapidly developing kick.

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

RCD Sealing Element (Packer). The elastomeric sealing element installed inside the rotating control device to seal around the drill string.

Secondary Barrier. Term used to back-up to the first barrier (i.e., the BOP system, casing, casing cement, and the wellhead collectively referred to as the secondary barrier envelope).

Subsea Mud Lift (SML). A form of MPD utilizing pumps located on the sea floor to pump the mud and cuttings returns back to the surface. This system may also employ a rotating seal above the BOPs and can create or reduce back-pressure on the wellbore by varying the pump operating speed and RCD configuration.

Subsea Service. Descriptive term used to apply to any item intentionally used in a wet condition below the sea water level. Subsea service requires multiple design features for that purpose, depending on each piece of equipment.

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

Well Control (Choke) Manifold. Part of a specially-designed section of piping installed on a drilling rig for use during well control incidents and not for MPD. This manifold and any associated choke(s) are designed for lower flow rates and higher pressures than those used for drilling.

23 Abbreviations

ABS	American Bureau of Shipping
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
CDS	Classification of Drilling Systems
CML	Controlled Mud Level
CoC	Certificate of Conformity
DGD	Dual Gradient Drilling
ECD	Equivalent Circulating Density
FMEA	Failure Mode and Effects Analysis
FMECA	Failure Mode, Effects and Criticality Analysis
IADC	International Association of Drilling Contractors
IRC	Independent Review Certificate
LAM	Light Annular Mud
MAC	Manufacturer’s Affidavit of Conformance
MASP	Maximum Anticipated Surface Pressure
MCD	Mud Cap Drilling
MGS	Mud-Gas Separator
MLP	Mud Lift Pumps
MPD	Managed Pressure Drilling
MRL	Mud Return Line
MUX	Multiplex Systems
NDE	Non-Destructive Evaluation
NRV	Non-Return Valve
P&ID	Piping and Instrumentation Diagram
PDA	Product Design Assessment
PFD	Process Flow Diagram
PMCD	Pressurized Mud Cap Drilling
PQR	Procedure Qualification Record
PRV	Pressure Relief Valve
RCD	Rotating Control Device
SAC	Survey after Construction
SBP	Surface Back-Pressure
SIT	System Integration Testing
SML	Subsea Mud Lift
SPM	Subsea Pump Module
SPU	Solids (cuttings) Processing Unit
SR	Survey Report
SRCD	Subsea Rotating Control Device
WPS	Weld Procedure Specification

SECTION 2 Design of MPD Systems, Subsystems and Equipment

1 General *(1 May 2018)*

This section provides design principles and technical requirements for the classification and certification of MPD systems, subsystems and equipment. Depending on the requested notation and the specific MPD system, the requirements in this section are to be applied as follows:

- For the **ABS MPD** notation, Subsections 2/3 through 2/9 and 2/17, and the additional system specific requirements as indicated below:
  - Subsection 2/11 for Back-Pressure systems
  - Subsection 2/13 for DGD systems other than CML
  - Subsection 2/15 for CML systems
- For the **ABS MPD-Ready** notation, Subsections 2/3, 2/5, 2/7, and 2/17

3 MPD System General Safety Considerations

In addition to the design principles which are included in this Guide, the general design of all MPD systems are to consider the principles contained in Sections 2 and 3 of the *CDS Guide*.

i) The MPD system is to be designed such that a single component failure in one of the MPD subsystems will not lead to an unsafe situation.

ii) According to the safety principle contained in API RP 14C, Section 5.4, the MPD control system is to be provided with at least two levels of protection to prevent or minimize the effects of an upset operational condition.

iii) During all MPD operations, the ability to immediately activate the rig's well control system is to remain unaltered by the use of MPD. The MPD system is to be designed to allow switching from MPD to conventional well control and vice versa as required.

iv) The "secondary barrier" system components are not to be used for routine or planned events in MPD operations. In an event where secondary barrier equipment is used for MPD operations, the risk involved is to be evaluated by performing a risk assessment and appropriate mitigations are to be put in place.

v) For back-pressure applications, the MPD system is to be able to maintain the appropriate pressure during all drilling and non-drilling operations unless some other means of controlling formation pressure is in place (e.g., downhole barrier valve, etc.).

5 Risk Assessment for MPD System

Risk assessments (as described below) are to be performed to identify all potential hazards and to confirm that appropriate mitigations are in place for each hazard identified during this process. The ABS *Guidance Notes on Risk Assessment Application for the Marine and Offshore Oil and Gas Industries* contains a description of the most common hazard identification techniques and additional information on their application.

The ABS *Guide for Risk Evaluation for the Classification of Marine-Related Facilities* contains details on the risk evaluation process for classification of alternative arrangements. In addition, Appendix 2 in that Guide provides an overview of how to assemble an appropriate risk assessment team.

ABS' participation in the hazard identification meeting(s) is recommended. Tangible benefits can be derived by the participation of an ABS representative who will later be directly involved in reviewing the designs for ABS Classification.

The risk assessments for MPD systems are to be in accordance with 2/5.9 and 2/5.11 of the *CDS Guide* and 2/5.1 through 2/5.5 of this Guide.

5.1 HAZID

At the initial planning stage, a HAZID study (or equivalent preliminary risk assessment technique) is to be performed to identify any additional wellbore system risks that would not normally be present in conventional drilling or created as a result of MPD modifications.

5.3 HAZOP

After sufficient MPD details have been developed, a HAZOP (or equivalent detailed risk assessment technique) is to be performed. The HAZOP is to consider the entire MPD system and all interfaces with the rig's existing systems. The HAZOP is to also address all MPD contemplated operational modes.

5.5 FMEA/FMECA

Functional and component level FMEA/FMECA for all major subsystems and equipment are to be performed. Major subsystems will, as a minimum, include the following when present:

- MPD riser joint, including all related equipment
- All MPD manifolds (buffer, choke, metering, or injection)
- MPD control system
- PRV valves, actuators and control system
- Any other MPD subsystems or equipment deemed to be essential to carry out MPD operations

FMEA/FMECA validation tests are to be carried out during factory acceptance testing and/or as part of the onboard commissioning of the integrated systems in accordance with the approved FMEA/FMECA test plans and verified by the attending Surveyor.

When final testing requires assembly and installation on-board the facility, it may not be possible to perform all required testing at vendor's plant. In this case, FMEA/FMECA validation testing is to be carried out as part of the system integration testing (SIT) during commissioning. Any modifications made to the validation test plan are to be submitted for review.

7/1.11 of the ABS *Guidance Notes on Failure Mode and Effect Analysis (FMEA) for Classification* provides detailed steps for FMEA/FMECA and FMEA validation testing.

7 Rig Modifications

In some instances, drilling rig modifications are required to accommodate MPD system prior to their installation or to facilitate MPD operations. The extent of these modifications are rig specific, MPD system specific, and site specific. Rig modifications are to be in accordance with applicable codes and standards, such as API RP 92S and RP 92M.

9 System Design

The design of MPD system and equipment are to comply with the following requirements:

i) All equipment included in the MPD system is to be designed to withstand the maximum system pressure for all MPD operational modes. For example, some of the operational modes include:

- Routine drilling ahead
- Making a connection
- Tripping pipe into or out of the well
- Running casing
- Running a liner
- Pumping a sweep
- Pumping cement

ii) The RCD and equipment in the drilling riser string below the RCD, are to be designed for combinations of pressure, tension, bending, and other applicable loads per design conditions. For more details, refer to the requirements contained in Subsection 2/11.

iii) Means of providing isolation below the RCD is required to allow replacing the RCD sealing assembly without having to close a BOP. When this is not provided as a part of the MPD system, justification is to be provided through the risk assessment in accordance with Subsection 1/17.

iv) MPD equipment are to be installed in such a way as to not interfere with, compromise or impact the secondary well control functionality of the rig's BOP well control system.

v) MPD equipment exposed to well bore fluids are to be compatible with all fluids, including H_2S which may be encountered within the scope of intended operations and service conditions. The drilling riser is not required to be compatible with H_2S.

vi) The MPD system is to be provided with pressure relief valve(s) (PRVs) to protect against over-pressure in accordance with provisions found in 2/1.5 of the *CDS Guide* and 2/11.9 of this Guide.

vii) Any discharge from the pressure relief valves (PRVs) are to be diverted to locations which are safe for both the fluid type(s) and volume being discharged.

viii) If a separate PRV discharge tank is provided to measure and monitor fluids, is to include the following:

a) Visual level indicator with remote monitoring capability

b) Volume measurement capability

c) Piping provisions to empty the tank into the rig’s mud system

d) Appropriate tank venting

ix) A redundant PRV is to be provided upstream of the choke manifold with an independent power source and control system.

x) For MPD operations where the RCD is installed below the riser tension ring, two mud return flow lines from the flow spool are to be provided.

xi) For back-pressure applications, each mud return line is to be connected to the modified riser joint flow spool with two (2) isolation valves for redundancy and these valves are to be fail-safe “as is” in order to protect the primary barrier.

xii) All valves upstream of the last isolation valve on the metering manifold used in MPD systems are to be capable of allowing full flow and holding pressure from either direction. Through risk assessment, alternative arrangements can be considered in accordance with Subsection 1/17.

xiii) All piping and materials are to follow the requirements of Sections 5 and 6 of the *CDS Guide* respectively. These requirements are to be supplemented by additional requirements contained in this Guide.

xiv) Piping and valves are to be arranged to divert flow overboard or to some alternate safe location upstream of the MPD choke manifold in case of an emergency or in a riser gas handling/riser gas management event.

xv) For back-pressure applications, a MPD choke manifold is to be provided to manage or maintain wellbore pressure.

xvi) For back-pressure applications, a minimum of two automatic chokes are to be provided as follows:

a) The system is to be designed to allow the chokes to be isolated while the manifold is in use.

b) Dedicated MPD choke manifold is to be designed and sized such that discharge pressures fall within the limits of the rig's conventional mud solids separation system. This manifold is to be separate and fully independent from the rig's well control (choke and kill) manifold system.

c) The MPD surface system and its components are to be selected and sized to handle solids-laden fluids, to not become a choke point and create any significant back-pressure.

d) In order to avoid erosion, the MPD system's piping diameter(s) are to be selected such that the flow velocity throughout the system is maintained below 5.5 m/s (18 ft/s). If higher fluid velocities are proposed, justification is to be provided by calculations and/or evidence showing that actual erosion rates under similar circumstances is suitable for the system's design life.

xvii) Continuous monitoring of both fluid density and flow rates for flow both going into and coming out of the well is to be provided in order to monitor influx and other well conditions at all times. If this provision is not fully met, then justification is to be provided for alternate arrangements in accordance with Subsection 1/17.

xviii) When an MPD choke manifold is installed, it is to be connected to the mud-gas separator (MGS) or downstream from the rig's well control (choke and kill) manifold.

xix) MPD equipment installed below the waterline is to be designed for subsea service.

xx) MPD systems are to be designed with the capability for allowing live maintenance during MPD operations. A justification for this selected design choice is to be evaluated as part of the risk assessment.

11 Back-Pressure Systems, Subsystems and Equipment Design

Back-pressure systems, subsystems and equipment are to be designed per applicable codes and standards and the additional requirements in this Guide. All valves and chokes used in flow spool, buffer manifold, choke manifold, and metering manifold are to be designed and manufactured to API Spec 6A PSL 3 requirements. Back-pressure system, subsystem, equipment and components are to be designed, manufactured, and tested in accordance with the latest versions of API RP 92C, 92M, 92P and 92S and the additional requirements listed as follows:

11.1 Low Pressure Riser above the Rotating Control Device (RCD)

All subsea MPD systems will require a low pressure riser in the system above the RCD. The low pressure riser is to comply with requirements listed in Subsection 3/5 of the *CDS Guide*, and the additional requirements listed below:

- The low pressure riser is to be connected to flow line, diverter, and other elements of the rig's drilling fluid circulation system.
- The riser section is to be provided with gas detection and leak detection.
- For RCD leak detection, mud level monitoring in the low pressure riser is to be provided such as a trip tank.

11.3 Rotating Control Device (RCD)

The RCD body, connections and individual bearing/sealing assembly are to be designed, manufactured, and tested in accordance with the latest version of API Spec 16RCD and the additional requirements as follows:

i) *Pressure Ratings.* The body/shell, static (non-rotating), the dynamic (rotating), and the stripping pressure ratings are to be specified by the manufacturer and validated in accordance with API Spec 16RCD.

ii) *Static and Dynamic Pressure Ratings of RCD*. The dynamic pressure rating of the RCD is to be capable of sealing the maximum anticipated MPD circulating pressure against the rotating drill pipe at a given RPM.

The static (non-rotating) pressure rating of the RCD is to be capable of containing the lesser of either the maximum anticipated MPD applied pressure or the highest planned stripping pressure against the non-rotating drill pipe.

For floating rig applications with a below tension ring RCD, additional loads on the RCD are to be considered, as specified in 3/5.3 of the *CDS Guide*, pertaining mainly to the additional types of design loads and pressure limits imposed on RCD body due to being an integral part of the riser.

When the RCD is installed above the tension ring, additional loads on the RCD are to be considered, as specified in 3/5.3 of the *CDS Guide*, as applicable.

iii) RCDs are to be designed to maintain the MPD operating envelope.

iv) RCDs are to be provided with a minimum of two packing elements for wellbore fluids. Alternative designs can be considered on a case by case basis through risk assessments in accordance with Subsection 1/17 of this Guide.

v) RCDs used on floating MODUs are to be designed and installed such that the packing elements can be safety changed without retrieving the entire RCD assembly in the drilling riser.

vi) A means of equalizing or bleeding trapped pressures below the packing element is to be provided.

vii) The locking mechanism/system of the RCD insert is to be of a type that provides feedback to monitor the locking function of the latch.

viii) The locking mechanism/system control of the RCD insert is to be designed to prevent unintentional or accidental release/unlocking of the latch. (e.g., interlock, 2-handed operation, flip-cover, etc.).

ix) The accumulator, control, and/or power system used to operate the RCD are to be independent of the rig's standard BOP accumulator system.

x) For surface RCD installations, a spillage containment system is to be provided to contain all spillage from the RCD. An outlet from this system is required to divert mud to an appropriate location.

11.5 MPD Annular

For floating MODUs, an MPD annular is to be installed below the RCD and above the flow line spool as part of a modified riser joint to isolate the RCD from wellbore and to facilitate RCD sealing element change-out or maintenance. The MPD annular can be used to isolate the RCD during emergencies such as a gas in riser event. Accordingly, an MPD Annular is to be included in all riser load considerations. See 2/11.27 for more information on modifications to drilling riser systems. Additionally, the following are to be complied with:

i) The MPD annular and its control system are to be designed and constructed per requirements found for an "annular preventer" or "annular BOP" as listed in Section 3 of the *CDS Guide*, API Spec 16A, and API Spec 16D, except this device is not required to close on the open hole (i.e., without pipe being in the well). The minimum pipe diameter to close is to be specified by the Owner/Operator. Any other exception to API Spec 16D is to be documented and submitted to ABS.

ii) The MPD annular device is not to be used as a replacement for any well control equipment, since it is not installed, maintained, or tested for well control.

iii) Being an integral part of the drilling riser, additional loads are to be considered for the MPD annular, as specified in 3/5.3 of the *CDS Guide*. The design of the MPD annular body and end connections are to consider these loads.

iv) Design of end connections are to be per API RP 16Q, Spec 16F, TR6 AF1 and TR6 AF2 or equivalent. It is noted that the loads on the MPD annular end connections are not fully defined in API Spec 16A for annular preventers. Using the methods described in API TR 6AF1 and 6AF2, the combined bending, tension and internal pressure loads are to be used to evaluate the MPD annular design.

11.7 Riser Flow Spool

A riser flow spool (positioned below the MPD annular) is a pressure-containing, cylindrical piece of equipment including end connections and side outlets. The side outlets are to be designed in accordance with API Spec 16A, Spec 6A, TR6 AF1 and TR6 AF2, as applicable. Design specifications of the flow spool is to be in accordance with the provisions for drilling spools listed in 2/11.27 for the modified riser joint.

11.9 PRV and Discharges

MPD subsystems, equipment, and/or components that may have the potential of exposure to pressure greater than its design pressure are to be protected by suitable overpressure protection devices such as relief valves. The following are to be considered:

i) Each part of the MPD system upstream of the choke manifold which may be exposed to a pressure greater than its design pressure is to be protected from overpressure by a relief valve.

ii) For rigs using a subsea BOP stack, all components between BOP and MPD choke are to be protected from overpressure by a relief valve. The location(s) of the overpressure protection devices/PRVs is to be justified through the risk assessments.

iii) All PRV(s) are to be sized, designed, fabricated, tested, and installed in accordance with the following principles, as applicable:

  a) Designed, fabricated, and tested to API Spec 6A PSL 3

  b) Safety principles of API RP 14C

  c) Relieving capacity are to be sized per API Standard 520

iv) The relieving capacity of the PRV and the discharge piping is not to be less than the combined maximum full-flow capacity of the drilling unit's mud pumps. As an alternative, well-specific calculations are to be provided which demonstrate the adequacy of the relieving capacity for all operational modes being provided. This calculation is to also consider emergency scenarios such as handling gas in riser.

v) Each pressure relief valve (PRV) is to be installed such that it is at the highest point possible and in such a manner that there is no possibility of accumulation of debris on the PRV inlet.

vi) The PRVs may be of either passive or active type. Where active PRVs are provided, the following additional requirements apply:

  a) In the event of a loss of rig power, the PRV is to remain operable until any ongoing MPD operations can be suspended and the well fully secured. The PRV control/operating system is to be provided with sufficient back up power supply.

  b) A redundant PRV is to be provided upstream of the choke manifold with an independent power source and control system as specified in 2/9ix).

vii) Remote indication of activation/status of each PRV is to be provided.

viii) All PRVs are to return to their current (pre-release) settings after each pressure-release event to maintain the system pressure.

ix) Relief valves are to be set at pressures which do not exceed the design pressure of the piping system. The piping system is to be designed to minimize back-pressure in the PRV discharge lines.

x) Relief valve discharge piping is to be designed to prevent any obstructions or blockages and are to be open to safely discharge at all times. Any possibility of obstructions or blockages are subject to special considerations and is to be evaluated through the risk assessments.

xi) The PRV discharge piping is to be designed and installed considering the following:

- Any vertical static gradient
- Potential for line plugging
- Exposed fluid stream composition including the potential exposure to hydrocarbons
- Access for maintenance provisions

In addition, the following requirements apply:

- PRV discharge lines are to have flushing capability
- Selected relief path is to offer less resistance (friction losses) than the original flow path
- Discharge piping is to be secured in accordance with 2/9.15.

11.11 MPD Manifolds

Depending on the design of the MPD system, the MPD manifold (buffer, choke, metering, or injection) may be one skid or may consist of multiple sections and/or manifolds.

i) The manifold piping is to be in accordance with Section 5 of the *CDS Guide*. Additional provisions are contained in 2/9xvi)d) of this Guide.

ii) MPD manifolds are to be designed, manufactured, and tested in accordance with the latest versions of API Spec 6A and API Spec 16C, as applicable.

iii) If the manifold(s) is/are mounted on a skid(s) (for handling or installation purposes), each skid is to comply with the provisions found in Subsection 3/23 of the *CDS Guide*.

iv) The MPD manifold(s) is/are to be sized and arranged in accordance with Subsection 2/9 of this Guide and the additional requirements listed below:

a) MPD manifolds are to be sized appropriately to avoid impairing the overall system performance. The following factors are to be considered for MPD manifold sizing:

- Total system pressure drop is to be kept to a minimum.
- Flow velocity is to be maintained at less than 5.5 m/s (18 ft/s) to avoid erosion/washout due to high velocity, solids-laden fluid flow.
- If higher fluid velocities are proposed, justification is to be provided by calculations and/or evidence showing that actual erosion rates under similar circumstances is suitable for the system's design life, as specified in 2/9xvi)d)
- Choke flow control trims are specifically excluded from the 5.5 m/s (18 ft/s) flow velocity limitation.
- Reduce the potential for line plugging by solids-laden fluid.

v) A buffer manifold, or a functionally equivalent piping, located upstream of the choke manifold is to be provided to direct the well fluids to the rig's shakers, rig's choke manifold, rig's gas buster, overboard lines, or to the MPD choke manifold.

vi) The MPD choke manifold is to comply with the following requirements:

a) Have a minimum of three flow paths as follows:

- Two choke paths to provide operational redundancy
- One flow path to bypass the chokes at any time

b) Have a tie–in for annulus injection during mud cap drilling

c) Valve actuators may be manual, hydraulic, electric, or pneumatic. Where remotely-operated chokes are installed, two independent means of control are to be provided or manual overrides are to be provided. For alternative arrangements, justification through risk assessments in accordance with Subsection 1/17 are to be provided to ABS.

All manifold isolation valves are to have a visible indication of valve's current position, both on remote monitoring screens and on the actual valve body. For remotely operated MPD chokes, this indication needs to be provided only on remote monitoring screens and local panel (if provided).

d) The following manifold instrumentation is to be provided to allow remote monitoring of the manifold(s):

- Flow rate, flow density, pressure, temperature, choke position, and valve status.

vii) Metering Manifold

a) Flow meters are to be installed, typically downstream of the MPD choke to measure outflow fluid mass flow rate, flow density and temperature for the MPD control system. The typical measurement device is a Coriolis meter, however, an alternative functional equivalent may be considered by ABS on a case-by-case basis.

b) The sizing of the flow meter system is to consider fluid types and flow rates of the MPD system.

b) A bypass is to be provided for maintenance of each meter, and for clearing any associated pipe blockages.

d) Flow metering device(s) are to be installed such that the discharge side will maintain back-pressure while working.

e) Discharge piping from metering manifold is to be directed to one or more of the following destinations:

- The rig’s shaker
- The rig’s choke manifold
- The rig’s MGS (when it has been shown to be adequately sized)
- A functional equivalent of this separator, as described in 2/11.21

11.13 Debris Catcher/Junk Catcher

A debris catcher may be installed upstream of the MPD choke manifold to avoid plugging of choke and other critical piping components.

i) If the debris catcher is installed, a provision for cleaning and bypassing it is to be provided.

ii) If it is not installed or alternate arrangements are provided, this is to be considered as part of the risk assessment.

11.15 Piping

MPD piping is to be designed per the requirements of Section 5 of the *CDS Guide*. Additionally, the following is to be adhered to:

i) Designs are to consider minimizing:

a) Back-pressure

b) Internal erosion/washout

c) The accumulation of solids or plugging due to particle bridging.

ii) Piping is to be properly secured according to provisions found in Subsection 6.4 of API RP 14E and ANSI/ASME B31.3 (on support requirements) to minimize any unwanted movement during MPD operations.

iii) Piping downstream of MPD chokes is to be designed or protected to guard against possibility of over-pressurization due to obstruction, blockage, or similar obstacles.

11.17 Flow Lines Including Flexible Lines

MPD systems are to be provided with rigid and/or flexible flow lines to enable fluid flow continuity with the wellbore annulus. The pressure design is to comply with Section 5 of the *CDS Guide.* Additionally, the following requirements also apply:

i) The design is to be in accordance with the requirements of API Spec 7K, FSL 1 at minimum and API RP 17B with respect to dynamic loading. Inner linings and other layers are to be designed per API Spec 17K requirements for exposure to wellbore fluids (oil, brine, hydrocarbon gases, H_2S, CO_2, etc.), green cement or cement slurries. Other linings and layers suitable for the intended service will be considered by ABS if found to be acceptable based on evidence from testing (e.g., full-scale blistering test as per API RP 17B).

ii) Flow lines/flexible lines are to have a design life of 5 years or longer.

iii) Flexible lines are to be designed such that allowable stresses meet the requirements of API Spec 17J and API Spec 17K under all loading conditions considering combined loading of internal pressure, external pressure and axial tension and bending.

iv) Design temperatures are to be suitable for the anticipated wellbore fluid temperatures.

v) Flow lines/flexible lines on floating installations are to be designed and installed in such a manner that they will accommodate all anticipated rig rotational movements.

vi) Flow lines/flexible lines are to be configured to minimize the following situations:

a) Potential for entanglement during MPD operations

b) Any likely contact with the hull during MPD operations and/or any adverse weather conditions

c) The effect of unsupported length:

- When the flow line is attached directly on the flow spool gooseneck from the moonpool deck, there is a significant increase in unsupported length of the flow line, which may result in additional tensile load. This is to be considered in each riser design calculation.
- For surface installation, where flow lines are connected to RCD outlet wing valves from the moonpool deck, the effect of unsupported length of the flexible line is to be considered in the calculation.

11.19 Back-Pressure Pump (BPP)

Certain MPD systems and related operations may need continuous annulus pressure management during tripping in and out, and ECD management during connections, or shut-in. For this purpose, dedicated back-pressure pump skids, or the drilling unit's mud pumps or riser booster pumps may be used. The following are to be considered if a BPP is provided:

i) The pump is to be suitable for both continuous and intermittent use, including

a) Sufficient output volume to operate chokes and function flow meters

b) Speed control to allow varying the output during connections

ii) Where cross-wellhead circulation is employed and oil-based muds are used, the BPP is to be designed so as to prevent hazards such as heat accumulation.

iii) A back-up power supply, independent of the main power supply is to be provided to maintain back-pressure (in case of dedicated BPP).

iv) A gravity-feed and/or a charge pump supply is to be provided in the design of the pump system to maintain uninterrupted, positive fluid suction to the pump.

v) Where a rig pump is used for MPD operations as an alternative or as a backup to a dedicated BPP, the potential for any impact to routine operations (such as drilling, running casing, and setting cement plugs during abandonment) are to be evaluated as part of the risk assessment.

vi) In-line non-return valve(s) are to be installed to prevent backflow.

vii) If a BPP is included as part of the MPD system deployed, a suitable pump safety system is to be used.

11.21 Mud-Gas Separator/Drill Thru Degasser

Under certain conditions, return flow may contain entrained gas and require it to be directed to a mud-gas separator (MGS). The MGS is to be designed per 3/3.5.4 through 3/3.5.7 of the *CDS Guide* and the following additional requirements are to be considered as applicable:

i) If the rig's MGS is considered insufficient based on expected maximum liquid or gas flow rates during MPD operations, a dedicated MPD MGS is to be installed which is capable of handling the maximum potential flow rates of liquid and gas. For existing-rig MPD conversions, if sufficient deck space, and/or deck loading capacity is not available for installing a dedicated MPD MGS then as an alternative, procedural mitigation will be considered by ABS with supporting risk assessment for the use of rig's existing MGS.

ii) The design calculations for the separator system(s), including both upstream and downstream piping diameters, run lengths, and the numbers of turns, verifying that the piping is capable of delivering returns throughout all operations and variations in flow rate at acceptably low pressures are to be submitted.

iii) A suitable system to enable management of pressures and fluid levels is to be provided.

iv) Calculations demonstrating that the flare or vent piping provided is of sufficient diameter for total flow capacity, maximum flow rate, back-pressure generated, and fluid velocity (for erosion tendencies).

v) When the desiccated MPD MGS is tied to the rig's MGS, the sizing calculation is to consider the back-pressure generated by the rig's MGS on the MPD MGS.

vi) When the MPD MGS is the same as the one used for well control, means to isolate the MPD piping system from the MGS is to be provided. This is to be considered a part of the risk assessment.

11.23 Non-Return Valve (NRV)

All SBP-MPD and PMCD-MPD drill strings will have two NRVs, appropriately placed to prevent backflow. NRVs are to be designed, constructed, and tested per API Spec 7NRV, or an equivalent technical specification.

11.25 Control Systems

Control system for riser mounted components, buffer manifold, choke manifold, PRVs, metering manifold, etc. are to follow the requirements of 2/7.19 and 3/15 of the *CDS Guide* and the additional requirements listed below:

i) The MPD system is to have the ability to be controlled from at least two locations to allow for any unforeseen conditions. One panel is to be located as near as possible to the driller's console.

ii) Umbilicals are to be provided with storage reels, along with proper deployment and retrieval systems. Necessary equipment to operate and maintain these components are to be also provided.

11.27 Modifications to the Drilling Riser System

MPD systems may need modifications to the existing drilling riser system to accommodate the MPD system riser components. This may necessitate a review of existing emergency disconnect procedures while in use. Typically, modified riser joints are required to accommodate all MPD system riser components (e.g., transition joints, RCD, MPD Annular, flow spool, etc.). Modified riser joints are to be designed per Subsection 3/5 of the *CDS Guide* and API Spec 16F and RP 16Q. The following additional requirements are to be applied to MPD modified riser joints designed to be installed below riser tension ring:

i) The drilling riser design calculations are to be modified to include effects of back-pressure imposed during MPD operations.

ii) Fully-assembled modified riser joint are to be able to pass through the rotary table.

iii) Joint inner diameter (without RCD sealing element installed) is to be such that it does not impact riser system drift diameter. If the above requirement is not met, justifications are to be provided to ABS for review.

iv) In instances where the RCD seal element is not run, the modified riser joint design is to permit routine conventional drilling operations to be carried out without any modifications.

v) Terminations for flexible lines and control lines are to be provided with gooseneck or equivalent connections, with the capacity of withstanding all likely dynamic and pressure loads.

vi) Joints are to be designed to incorporate the fluid lines and control lines required for the subsea functions (e.g., BOP). Such lines could include: choke, kill, booster lines, mud return lines, hydraulic supply, and electrical/MUX/umbilical lines.

vii) Incorporate a stab-plate arrangement for the connection of umbilical/control lines or include a functional equivalent.

viii) MPD riser joint is to be rated for the specified design conditions of the rig's drilling riser system.

ix) The entire MPD riser joint, including the control system, is to have an FMEA/FMECA analysis performed and submitted for review.

x) MPD riser joint running tools are to be designed, manufactured, and tested in accordance with the latest version of the API Spec 16F.

13 Dual Gradient Systems

The IADC has defined four subsets of DGD techniques as listed below:

1. Riser-less mud returns for pre-BOP drilling.

2 .Subsea mud-lift (SML) (for post-BOP drilling).

3. Dilution-based DGD (for post-BOP drilling, requiring specially-built centrifuges.

4. Controlled Mud Level (CML) for post-BOP drilling.

The first three subsets of DGD systems including SML systems may be classed as per Subsection 1/13 0f this Guide. The ABS *Guidance Notes on Qualifying New Technologies* and the ABS *Guidance Notes on Review and Approval of Novel Concepts* provides a methodology that may be used for approval of these designs and their incorporation on an asset. CML systems are to comply with the requirements as per 2/15 of this Guide.

15 Controlled Mud-Level Systems, Subsystems and Equipment Design

All process valves are to be designed and manufactured to API Spec 6A PSL 3 or API Spec 6DSS requirements. For subsea applications, valves designed and manufactured to API 6A are also to meet the provisions in API Spec 17D, as applicable. For near-surface applications such as below tension ring flow spools and valves, these items may not require compliance with API Spec 17D as long as the designer justifies the suitability of each component.

Any modifications to conventional well control necessitated by CML-MPD procedures being planned is to be evaluated by the risk assessment in accordance with Subsection 1/15.

In addition, the following requirements are to be met:

15.1 Subsea Pump Module (SPM)

The system design specifications for the subsea pump module are to be submitted to ABS for review. In particular, the following information and system details are to be included:

i) The weight and size of the SPM to be used in riser load analysis.

ii) Minimum and maximum allowable sustained flow rates and pressures able to be delivered by the SPM as installation depth and mud weight varies, together with the power required for these variations.

iii) Maximum electrical power supply required, including a statement describing where this power will originate, along with any necessary source(s) for a back-up electric power supply for the SPM.

iv) If an external power supply is required (for either main or back-up electrical power), then a structural analysis is to be carried out considering the additional loads for this external power supply, including the weights for storing all required supplemental fuel supplies. The HAZOP analysis is to consider the added risks of utilizing the extra generator including exhaust gas routing, structural loading considerations, and fuel transportation, loading and storage.

v) A method for securing the SPM power umbilical to prevent any potential interference with rig thrusters is to be provided. This method considering installation and retrieval is to be evaluated as part of the risk assessment.

vi) Method of fluid monitoring for return levels of flow as specified in 2/9xvii).

15.3 Low Pressure Riser above Subsea Pump Module

The low pressure riser is to comply with the applicable requirements listed in 2/11.1 and the additional requirements as listed below:

i) The low pressure riser is to be connected to all of the rig's customary riser top connections including the flow line, diverter, riser tensioning system, choke and kill lines, etc., just the same as if the CML system were not deployed.

ii) The extra tension required due to the weight of the added mud return line (MRL) is to be taken into account in the drilling riser analysis as an additional load. Other additional loads are to be taken into account for wind, wave, and current loads due to the added section of riser (which extends down to the depth of the SPM).

iii) Method of fluid monitoring for return levels of flow as specified in 2/9.

15.5 Subsea Annular Isolation Device/MPD Annular

MPD annular above the SPM suction point is not generally required for CML operations, but if one is installed, it is to comply with 2/11.5.

15.7 PRV and Discharge

The CML system is a low pressure system. To safeguard against over-pressuring the system, the pressure rating of the piping downstream the subsea pumps is to not exceed the maximum pressures that the piping can be subjected to during operation or blocked flow.

If this cannot be demonstrated, a pressure relief valve (PRV) is to be used in accordance with 2/11.9.

15.9 Flow Manifolds

Depending on the system design, CML-MPD may have a flow manifold or piping to direct fluid coming up the MRL once it reaches the drilling unit. The design of the manifold is to be in accordance with 2/11.11.

15.11 Flow Meter

i) Flow meters are to be installed on the flow line to measure fluid volume, flow rate, etc., for a CML-MPD system. If the flow meter is part of another system with the signal shared with the CML control system, then this scenario is to be evaluated as part of the risk assessment.

ii) The size and pressure rating of the flow meter system are to be based on fluid types, flow rates, and pressure rating of the MPD system.

iii) To enable accurate measurements, the discharge piping from the flow meter is to be such that it will not create a vacuum and always maintain some back-pressure, even while making a drill string connection.

iv) The flow meter is to be installed according to the manufacturer's recommended practices. The installation is to be self-draining and is to not permit the accumulation of mud when not in use.

v) The discharge piping from metering manifold is to be directed to rig's shaker, rig's choke manifold, diverter, mud gas separator, or to a functional equivalent of this separator, similar to the requirements found in 2/11.21 for SBP-MPD systems.

15.13 Piping

All CML-MPD piping is to be designed per the requirements of 2/11.17 of this Guide and Section 5 of the *CDS Guide*. CML-MPD systems are to be provided with rigid and/or flexible flow lines to enable flow continuity with the wellbore annulus. The pressure design is to comply with 2/11.15 and the corresponding Section 5 of the *CDS Guide*.

15.15 Mud Return Line (MRL)

A CML-MPD system uses a mud return line to bring fluid from the subsea pump to the surface. The MRL is to be designed per the applicable sections of API Spec 16F and RP 16Q, as well as the following additional requirements:

i) The MRL is to be able to operate within the expected pressures and flow ranges anticipated, considering the following:

a) MRL pressure drop

b) Fluid velocity in MRL

c) A calculated expected erosion rate of MRL from recognized industry sources.

ii) Fluid compatibility verification on all elastomeric components is to be carried out as part of the basic design.

iii) Means for back flushing the MRL is to be provided with suitable frequency of flushing. A dedicated pump for back flushing may be used or an available rig pump may be used. If a rig pump is to be used, a flow diagram showing the alignment of piping, flexible lines, and valves is to be submitted to ABS for review.

CML-MPD systems that are designed using alternative arrangements other than MRL may be specially considered based on risk assessments in accordance with Subsection 1/17.

15.17 CML Control Systems

CML-MPD control systems are to meet Subsection 3/15 of the *CDS Guide*. The following additional requirements are to be applied:

i) Redundancy is to be provided for measuring the pressure in the riser.

ii) System philosophy is be developed for well control.

iii) Capability to prevent incorrect measurement of riser level from faults (e.g., transducer failure) is to be provided.

iv) Verification of pressure sensor measurements is to be provided.

v) In the event of any equipment failure, operating data is to be backed up and made readily available so that the well can be fully secured.

vi) Umbilicals are to be provided with storage reels and a proper deployment and retrieval system.

15.19 Modifications to the Drilling Riser System

CML-MPD systems may need modifications to the existing drilling riser system to accommodate CML-MPD riser components. A typical modified riser joint for CML may consist of a riser penetration for removal of drilling fluid, two riser isolation valves, redundant pressure transducers, a pedestal and mounting system for the subsea pump, control system components, umbilicals, and a piping arrangement that allows drilling fluid to be routed to the pump when it is docked onto the riser, as well as piping to divert discharge fluid to surface. The modified riser joint is to meet 2/11.27, as applicable.

17 Materials, Welding and Nondestructive Examination for MPD System

All materials used for MPD system/sub-system and equipment are to be in accordance with the requirements of Section 6 of the *CDS Guide*.

Welding and nondestructive examination (NDE) are to be qualified and performed in accordance with the requirements of section 7 of the *CDS Guide*.

SECTION 3 Survey of MPD Systems, Subsystems and Equipment

1 General

Surveys of the MPD systems, subsystems, and equipment are to be performed according to the applicable provisions contained in

i) Section 8 of the *CDS Guide* for surveys at vendor's manufacturing facility and surveys on-board during installation and commissioning

ii) Section 9 of the *CDS Guide* for surveys after construction for maintenance of class

iii) Additional requirements listed in the subsections below

For temporary installation of MPD system, the scope of survey is to be based on an agreement between ABS and the Owner/Operator or Designer/Manufacturer.

The general reference listing of MPD equipment provided in Section 3, Table 1 of this Guide specifies applicable documentation and testing requirements, arranged by major MPD systems, subsystems and equipment.

3 Surveys at Manufacturer and During Assembly

Surveys at the manufacturing facility are to be performed according to recognized industry standards as stated in Section 3, Table 2 and the pertinent provisions found in Subsection 8/3 of the *CDS Guide*.

5 On-Board Surveys during Installation and Commissioning

During installation and commissioning, on-board surveys are to be performed according to the applicable provisions in Subsections 8/5 and 8/7 of the *CDS Guide*, supplemented with the following:

i) MPD system, subsystem and equipment are to be connected and installed per the ABS-approved drawings as listed in 1/19 of this Guide.

ii) A pressure test and commissioning procedure is to be submitted to the attending Surveyor for review prior to testing.

iii) Pressure testing is to be conducted on board the unit. Low-pressure and high-pressure testing of subsystems/equipment is to be performed according to Section 3, Table 2 of this Guide.

iv) Pressure testing is to be performed after latching to verify that the RCD sealing element is locked. The pressure test is to be carried out at the rated working pressure of the RCD as determined in 2/11.3 of this Guide.

v) MPD riser joint components are to be tested to 1.5 times RWP at the manufacturer and the assembled MPD riser joint is to be hydrotested at RWP on board. Documented dimensional verification to approved drawings is required for those riser components not pressure tested at the factory.

vi) Function testing of subsystems/equipment is to be performed according to Section 3, Table 2 of this Guide.

7 Surveys after Commissioning

Surveys of the MPD systems, subsystems, and equipment after construction for maintenance of class are to be performed according to the applicable provisions in Section 9 of the *CDS Guide*.

9 MPD Systems and Equipment not Associated with a Specific Drilling Unit

MPD systems and equipment that have been designed and constructed to the requirements in this Guide may be used on units classed with ABS as detailed in this Guide and on other non-classed units. The Owner of the subsystem/equipment will be responsible to retain the certificates and maintenance records for each piece of equipment.

Prior to being installed in a classed drilling unit, the Owner is to present the required certification and maintenance documentation to the ABS Surveyor. Maintenance records are required to include ABS examination of the subsystem/equipment in accordance with 9/1.3 of the *CDS Guide*, including requirements for Annual and Special Periodical Survey.

TABLE 1
Codes for Design Review and Survey

Systems/ Subsystems	*Subsystems/ Equipment (All Notes apply)*	*Design Review*	*Survey (at vendor)*	*FMEA/ FMECA*	*Comments*	*General Reference (Informative)*	*Approval Tier Level (See Note 2)*
MPD (SBP/MCD/CML) System and Interface with Drilling System	MPD System	X	X	HAZOP			N/A
	Piping & Valves	X	X		Interface piping & valves See 2/11.15	API 6A, 6DSS, ASME B31.3	N/A
	Control System	X	X	X	See 2/11.25		N/A
	Electrical Equipment	X	X		Refer to *MODU Rules* Part 6		N/A
	Fire & Safety Equipment	X	X		Refer to *MODU Rules* Part 5		N/A
	Portable Industrial Modules	X	X		Refer to *MODU Rules* Part 7, Appendix 2		5
MPD Riser System	Assembled Modified Riser Joint	X	X	X		API 16F, 16Q, 16R	5
	RCD	X	X			API 16 RCD	5
	RCD Control System	X	X	X			
	RCD Bleed Line	X	X			API 7K	5
	RCD Bearing Assembly Running Tool	X			Design review is limited to Basis of Design		2
	MPD Annular	X	X			API 16A	5
	MPD Annular Control System	X	X	X			N/A
	Flow Spool & Valves	X	X			API 16F, 16Q, 16A, 6A, For end connections: TR6 AF1, TR6 AF2	5
	Flow Spool Valve Control System	X	X	X			N/A
	Gooseneck	X	X			API 6A, ASME B31.3	5
	Flow Line/Flexible Line	X	X			API 17B, 17J, 17K, 7K	5
	Upper & Lower Crossover	X	X			API 16F	5
	End Flange	X	X			API 6A, 16A	5
	MPD Riser Running & Handling Tools	X	X			API 16F	5
	Spider Adapter	X	X			API 16F	5
	Choke & Kill Lines	X	X			API 16C	5
	Auxiliary Lines	X	X			API 16D, 16F	5

TABLE 1 (continued) Codes for Design Review and Survey

Systems/ Subsystems	*Subsystems/ Equipment (All Notes apply)*	*Design Review*	*Survey (at vendor)*	*FMEA/ FMECA*	*Comments*	*General Reference (Informative)*	*Approval Tier Level (See Note 2)*
MPD Choke Manifold	MPD Choke Manifold Assembly including Skid	X	X	X	Includes structure, piping, valves and associated controls	API 16C, 6A	5
	MPD Choke	X	X			API 16C, 6A	5
	Piping & Valves	X	X			API 16C, 6A	5
	Control System	X	X	X			N/A
Metering Manifold	MPD Metering Manifold Assembly including Skid	X	X	X	Includes structure, piping, valves, Coriolis meter and associated controls		5
	Coriolis/ Mass-Flow Meter	X					2
	Piping & Valves	X	X			API 6A, ASME B31.3	5
	Control System	X	X	X			N/A
Pressure Relief Valve (PRV) System	PRV & Discharge	X	X	X		API 520, 6A, 14C	5
	Control System	X	X	X			N/A
Buffer Manifold	Buffer Manifold Assembly including Skid	X	X		Includes structure, piping, valves, and associated controls	API 6A	5
	Piping & Valves	X	X			API 6A	5
	Control System	X	X	X			N/A
Debris Catcher/Junk Catcher		X	X			API 6A	5
Back-Pressure Pump		X	X	X		Section 4, Table 1 of *CDS Guide*	5
MPD Dedicated MGS/Drill Thru Degasser		X	X			API 53, 16C	5
Drill String Non-Return Valve (NRV)		X	X			API 7-1	5
Subsea Pump Module	Frame	X	X				5
	Mud-lift Pump	X	X			Section 4, Table 1 of *CDS Guide*	5
	Auxiliary Load Bearing Components	X	X				5
	Piping & Valves	X	X			ASME B31.3	5
	Control System	X	X	X			N/A
Barrier Fluid Skid		X	X				5
Solids Processing Unit		X	X	X			5
Subsea Choke System	Subsea Choke & Valves	X	X			API 17D, 6A, 16C	5
	Control Systems	X	X	X			N/A

TABLE 1 (continued)
Codes for Design Review and Survey

Systems/ Subsystems	*Subsystems/ Equipment (All Notes apply)*	*Design Review*	*Survey (at vendor)*	*FMEA/ FMECA*	*Comments*	*General Reference (Informative)*	*Approval Tier Level (See Note 2)*
Flow Manifold	Piping & Valves	X	X			API 6A, ASME B31.3	5
	Control Systems	X	X	X			N/A
Mud Return Line (MRL)		X	X				5
Launch and Retrieval System (LARS)	LARS	X	X		See 3/11 and 8/3.7 of *CDS Guide*		5
	Cart Attachment Frame	X	X				5
	Control Systems	X	X	X			N/A
Backflush Pump		X	X			Section 4, Table 1 of *CDS Guide*	5

Notes:

1 MAC (Manufacturer's Affidavit of Compliance) is a document certified by a competent authority of the manufacturer that the specified product meets the required specifications. A MAC is required for all equipment listed in this table.

2 For optional ABS Type Approval Tiers, see 1-1-A2/A3 of ABS *Rules for Conditions of Classifications – Offshore Units and Structures (Part 1)*.

3 "Survey" requires the Surveyor attendance during fabrication, witness inspections and testing per rule requirements and design codes/standards in accordance with the agreed Inspection/Test Plan (ITP), verification to approved plans and issuance of a survey report. Section 3 details surveys at vendor's plant, during installation and commissioning.

4 IRCs and CoCs may be issued if requested. IRCs are part number specific. CoCs are part number and serial number specific.

5 For equipment common to drilling systems, see Section 4, Table 1 of the *CDS Guide*.

6 Tabular listing of references are provided for general reference purposes only (informative). Other industry standards may provide an acceptable basis for design.

7 Prototype testing is to be carried out as per the applicable design codes and standards.

TABLE 2
Codes for Testing

Systems/ Subsystems	*Subsystems/ Equipment (All Notes apply)*	*Factory Testing*	*On Board Testing*	*FMEA/ FMECA Testing*	*Testing Remarks*	*General Reference (Informative)*
MPD (SBP/MCD/CML) System and Interface with Drilling System	MPD System		RWP/FT	Action items from HAZOP		
	Piping & Valves	HPT/FT	RWP/FT		Interface piping & valves	API 6A, 6DSS, ASME B31.3
	Control System	HPT/FT	RWP/FT	VT	Hydrotest for hydraulic control piping	
	Electrical Equipment				Refer to *MODU Rules* Part 6	
	Fire & Safety Equipment				Refer to *MODU Rules* Part 5	
	Portable Industrial Modules				Refer to *MODU Rules* Part 7, Appendix 2	
MPD Riser System	Assembled Modified Riser Joint		RWP/FT	VT		API 16F, 16Q, 16R
	RCD	HPT/FT	RWP/FT			API 16 RCD
	RCD Control System	FT	FT	VT		
	RCD Bleed Line	HPT/FT	RWP/FT			API 7K
	RCD Bearing Assembly Running Tool				MAC verification by SAC Attending Surveyor	
	MPD Annular	HPT/FT	RWP/FT			API 16A
	MPD Annular Control System	FT	FT	VT		
	Flow Spool & Valves	HPT/FT	RWP/FT			API 16F, 16Q, 16A, 6A, For end connections: TR6 AF1, TR6 AF2
	Flow Spool Valve Control System	FT	FT	VT		
	Gooseneck	HPT	RWP/FT			API 6A, ASME B31.3
	Flow Line/Flexible Line	HPT/FT	RWP/FT			API 17B, 17J, 17K, 7K
	Upper & Lower Crossover	HPT/FT	RWP/FT			API 16F
	End Flange	HPT/FT	RWP/FT			API 6A, 16A
	MPD Riser Running & Handling Tools	LT	FT			API 16F
	Spider Adapter	LT	FT			API 16F
	Choke & Kill Lines	HPT/FT	RWP/FT		Section 4, Table 1 of *CDS Guide*	
	Auxiliary Lines	HPT/FT	RWP/FT		Section 4, Table 1 of *CDS Guide*	
MPD Choke Manifold	MPD Choke Manifold Assembly including Skid	HPT/FT	RWP/FT	VT	Includes structure, piping, valves, choke and associated controls	API 16C, 6A
	MPD Choke	HPT/FT	RWP/FT			API 16C, 6A
	Piping & Valves	HPT/FT	RWP/FT			API 16C, 6A
	Control System	HPT/FT	RWP/FT	VT	Hydrotest for hydraulic control piping	

TABLE 2 (continued) Codes for Testing

Systems/ Subsystems	*Subsystems/ Equipment (All Notes apply)*	*Factory Testing*	*On Board Testing*	*FMEA/ FMECA Testing*	*Testing Remarks*	*General Reference (Informative)*
Metering Manifold	MPD Metering Manifold Assembly including Skid	HPT/FT	RWP/FT	VT	Includes structure, piping, valves, Coriolis meter and associated controls	
	Coriolis/ Mass-Flow Meter		RWP/FT			
	Piping & Valves	HPT/FT	RWP/FT			API 6A, ASME B31.3
	Control System	HPT/FT	RWP/FT	VT	Hydrotest for hydraulic control piping	
Pressure Relief Valve (PRV) System	PRV & Discharge	HPT/FT	RWP/FT	VT		API 520, 6A, 14C
	Control System	HPT/FT	RWP/FT	VT	Hydrotest for hydraulic control piping	
Buffer Manifold	Buffer Manifold Assembly including Skid	HPT/FT	RWP/FT	VT	Includes structure, piping, valves, and associated controls	API 6A
	Piping & Valves	HPT/FT	RWP/FT			API 6A
	Control System	HPT/FT	RWP/FT	VT	Hydrotest for hydraulic control piping	
Debris Catcher/Junk Catcher		HPT	RWP/FT			API 6A
Back-Pressure Pump		HPT/FT	RWP/FT	VT	Section 4, Table 1 of *CDS Guide*	
MPD Dedicated MGS/Drill Thru Degasser		HPT	RWP/FT			API 53, 16C
Drill String Non-Return Valve (NRV)		HPT	RWP/FT			API 7-1
Subsea Pump Module	Frame	LT			Section 4, Table 1 of *CDS Guide*	
	Mud-lift Pump	HPT/FT	RWP/FT		Section 4, Table 1 of *CDS Guide*	
	Auxiliary Load Bearing Components	LT/FT	LT/FT			
	Piping & Valves	HPT/FT	RWP/FT			ASME B31.3
	Control System	HPT/FT	RWP/FT	VT	Hydrotest for hydraulic control piping	
Barrier Fluid Skid		HPT	RWP/FT			
Solids Processing Unit		HPT/FT	RWP/FT	VT		
Subsea Choke System	Subsea Choke & Valves	HPT/FT	RWP/FT			API 17D, 6A, 16C
	Control Systems	HPT/FT	RWP/FT	VT	Hydrotest for hydraulic control piping	
Flow Manifold	Piping & Valves	HPT/FT	RWP/FT			API 6A, ASME B31.3
	Control Systems	HPT/FT	RWP/FT	VT	Hydrotest for hydraulic control piping	
Mud Return Line (MRL)		HPT/FT	RWP/FT			
Launch and Retrieval System (LARS)	LARS	LT/FT	LT/FT		See 8/3.7 of *CDS Guide*	
	Cart Attachment Frame	LT				
	Control Systems	HPT/FT	RWP/FT	VT	Hydrotest for hydraulic control piping	
Backflush Pump	Pump	HPT/FT	RWP/FT		Section 4, Table 1 of *CDS Guide*	

TABLE 2 (continued)
Codes for Testing

Notes:

1 Testing is required per the design specification and the applicable sections of this Guide and test plans are to be submitted to the Surveyor for review. At the discretion of the attending Surveyor, test plans may be required to be submitted for technical review. When specified, "Factory Acceptance Testing" can be completed at installation due to the nature of the system, same is to be noted in the test plans. Section 3 details surveys at vendor's plant, during installation and commissioning.

2 MPD Equipment are to be tested in accordance with tests specified by the Manufacturer and this Guide. Low pressure and rated working pressure tests are required at Installation/Commissioning testing on board. Refer to API STD 53 for low pressure testing criteria.

3 Design validation testing may be required per the applicable design code.

4 For equipment common to drilling systems, see Section 4, Table 1 of the *CDS Guide*.

5 Tabular listing of references are provided for general reference purposes only (informative). Other industry standards may provide an acceptable basis for design.

6 Prototype testing is to be carried out as per the applicable design codes and standards.

7 Where multiple tests are indicated (e.g., HPT/RWP/FT), all tests are required.

Types of Tests

HPT Hydrostatic Proof Test per design specification

RWP Hydrostatic Proof Test at Design Rated Working Pressure

FT Function Test (Operational Tests without load/pressure applied)

LT Load Test as specified in the approved test plan.

VT FMEA/FMECA Validation Testing