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DRILLING AND COMPLETION COMMITTEE

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IRP RMD / MPD / UBD Operations

An Industry Recommended Practice (IRP)
for the Canadian Oil and Gas Industry

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CAOEC CANADIAN ASSOCIATION OF ENERGY CONTRACTORS
CAPP CANADIAN ASSOCIATION OF PETROLEUM PRODUCERS Canada's Oil and Natural Gas Producers
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22.0 Preface

22.0.1 Purpose

IRP 22 is a collection of guidelines for RMD, MPD and UBD operations. These guidelines can be used in the development, planning and completion of RMD, MPD or UBD programs. IRP 22 may be used as a reference for the intended audience, act as a guideline for MPD/UBD companies in training employees or assist in developing internal procedures for safe RMD/MPD/UBD practices.

IRP 22 provides information regarding planning, equipment considerations and operational practices. A key component to this IRP is the IRP 22 Risk Register. The Risk Register is a tool designed to allow RMD/MPD/UBD professionals to transfer this IRP into practice (see 22.4 Hazard Identification and Risk Assessment).

22.0.2 Audience

The intended audience for this document includes the following:

- RMD/MPD/UBD planners

All RMD/MPD/UBD personnel may find all or portions of this IRP of interest.

22.0.3 Scope and Limitations

The scope for this IRP includes land-based operations in western Canada (British Columbia to Manitoba and territories).

IRP 22 is not intended to replace local jurisdictional regulations. These regulations are referenced throughout the document.

This document discusses RMD, MPD and UBD using jointed pipe. Some information about coiled tubing and air drilling operations has been included for reference as it relates to RMD/MPD/UBD operations only. Consult IRP 21: Coiled Tubing Operations for detailed information about coiled tubing operations.

IRP 22 was developed with focus on Western Canadian onshore operations. Local jurisdictional regulations vary from province to province and must be consulted for each operation.

RMD/MPD/UBD operations are complex drilling projects. IRP 22 recommendations are meant to allow flexibility for continuous improvement with regard to safety and

operational efficiency giving consideration to the complex nature of RMD/MPD/UBD operations.

Competent technical judgment must be used in combination with these recommendations. It is the operator's responsibility to ensure that required and/or appropriate technical judgement is used to develop the project plan and during the execution of the project. They are also responsible for ensuring any experts providing technical judgement are qualified by normal industry standards (e.g., years of technical/operational experience, review of applicable completed projects, references, etc.) and should be able to demonstrate this upon audit.

22.0.4 Revision Process

IRPs are developed by the Drilling and Completions Committee (DACC) with the involvement of both the upstream petroleum industry and relevant regulators. Energy Safety Canada acts as administrator and publisher.

Technical issues brought forward to the DACC, as well as scheduled review dates, can trigger a re-evaluation and review of this IRP in whole or in part. For details on the IRP creation and revisions process, visit the Energy Safety Canada website at www.EnergySafetyCanada.com.

A complete list of revisions can be found in Appendix A.

22.0.5 Sanction

The following organizations have sanctioned this document:

Canadian Association of Oilwell Energy Contractors (CAOEC)

Canadian Association of Petroleum Producers (CAPP)

Enserva

Explorers & Producers Association of Canada (EPAC)

22.0.6 Range of Obligations

Throughout this document the terms 'must', 'shall', 'should', 'may' and 'can' are used as indicated below:

Table 1. Range of Obligation

Term	Usage
Must	A specific or general regulatory and/or legal requirement that must be followed. Statements are bolded for emphasis.

Shall	An accepted industry practice or provision that the reader is obliged to satisfy to comply with this IRP. Statements are bolded for emphasis.
Should	A recommendation or action that is advised.
May	An option or action that is permissible within the limits of the IRP.
Can	Possibility or capability.

22.1 Introduction

Managed Pressure Drilling (MPD) and Underbalanced Drilling (UBD) are two drilling techniques that manipulate pressure to either force or prevent the flow of formation fluids. IRP 22 uses the International Association of Drilling Contractors (IADC) definitions for MPD and UBD.

IADC defines MPD as “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 to the surface. Any influx incidental to the operation will be safely contained using the appropriate process.”

- MPD process employs a collection of tools and techniques which may mitigate the risks and costs associated with drilling wells that have narrow downhole environmental limits, by proactively managing the annular hydraulic pressure
- MPD may include control of backpressure, fluid density, fluid rheology, annular fluid level, circulating friction, and hole geometry, or combinations
- MPD may allow faster corrective action to deal with observed pressure variations. The ability to dynamically control annular pressures facilitates drilling of what might otherwise be economically unattainable prospects

IADC defines UBD as “A drilling activity employing appropriate equipment and controls where the pressure exerted in the wellbore is intentionally less than the pore pressure in any part of the exposed formations with the intention of bringing formation fluids to the surface.”

The presence of nuisance gas during some conventional jointed pipe drilling operations may require MPD/UBD equipment to handle the nuisance gas properly. However, this situation does not make this type of operation fall under the definition of MPD or UBD and to classify them as such would make them economically unfeasible due to the requirements associated with MPD and UBD. For that reason, a third category of drilling techniques has been recognized and IRP 22 refers to this as Returns Management Drilling (RMD).

IRP 22 defines RMD as “A drilling activity where hydrostatic drilling fluid weight could be less than the pore pressure of the formation but the well is not believed to be capable of flow to surface. The intention is to handle/respond to nuisance gas at surface with appropriate equipment.”

Note: RMD configurations do NOT include a choke. If a choke is added then the operation becomes MPD/UBD and requires MPD/UBD equipment and on-site personnel competent to use the equipment.

Note: An isolation valve is not designed to control flow or pressure and is not to be used as a choke.

For purposes of IRP 22, nuisance gas could be one or more of the following:

- Trip gas
- Drill gas
- Bottoms-up gas
- Connection gas

Note: A continuous flare may indicate that there is more than nuisance gas being dealt with. At this point it is necessary to review job parameters and equipment limitations to confirm that RMD is still appropriate (see 22.8.5.1 RMD Operations Matrix).

RMD equipment is often rented from a service company but is left to the renter to operate and maintain so it is important that the renter understands the purpose, limitations and regulatory restrictions for the equipment (see Appendix H: RMD Checklist and Appendix I: MPD Equipment Checklist).

While this IRP uses the IADC definitions for MPD and UBD, it recognizes that clarification or further definition of RMD/MPD/UBD may sometimes be required when applying for a well license. This clarification makes the distinction of whether MPD/UBD are actually the sole purpose for the drilling activity or whether the equipment is simply on-site for returns management and/or safety (RMD).

The expectations and characteristics of RMD are as follows:

- RMD equipment is used to handle nuisance gas (e.g., RCD and a dedicated atmospheric degasser).
- Hydrostatic drilling fluid weight could be less than pore pressure but the well is not believed to be capable of flow to surface (based on permeability and/or porosity of the formation).
- Equipment could be utilized for wells where drilling fluid weight is slightly higher than pore pressure for safety, performance or where offset information identifies the possibility of gas to surface.
- There are no MPD/UBD chokes. If a drilling choke is required then the job becomes/reverts to MPD or UBD and management of change is required (i.e., well application, personnel, equipment, etc.).

- If influx is taken it is circulated out via conventional means using the rig's well control equipment because there are no chokes. All kicks must be reported to the local jurisdictional regulator.
- This category allows for equipment rental where personnel are not supplied. RCD and degasser are rented to the rig and rig crew is responsible for equipment (i.e., must be trained).
- Under static conditions the well should not flow (i.e., based on flow check).
- Requires definite risk assessment for the zone (i.e., is there risk of fracture? Can the crew/rig handle these risks?).
- To be used for formations that are known to be sweet.

The expectations and characteristics of MPD are as follows:

- The hydrostatic drilling fluid weight plus surface applied pressure is at or greater than pore pressure at all times. This could also include control of the fluid density, fluid rheology, annular fluid level, circulating friction and hole geometry (or any combination thereof) to remain at or greater than pore pressure at all times.

  Note: Hydrostatic drilling fluid weight could be less than pore pressure if the well is not believed to be capable of flow to surface (based on permeability and/or porosity of the formation). Pressure is applied to balance the well.

- Formation fluid flow is not intentionally invited to surface (not consistently inviting a constant flare or flow drilling).
- Surface equipment is designed to handle expected surface pressures.
- Personnel who are trained and competent in MPD operations and equipment are required to run the equipment.

  Note: MPD equipment may be rented and personnel are not supplied. The equipment and competent personnel are then the responsibility of the renter.

The expectations and characteristics of UBD are as follows:

- The hydrostatic head of a drilling fluid is intentionally designed to be lower than the pressure of the formation being drilled and the intention is to have reservoir fluids returned at surface. The underbalanced condition could be achieved by relying solely on the reservoir pressure (flow drilling) or by reducing the hydrostatic head by introducing a gaseous phase as part of the drilling fluid (UBD).
- Equipment onsite is designed to handle the expected returns.
- UBD personnel are required to run the equipment.

Most of the information and recommendations in IRP 22 apply to both MPD and UBD. Where there are specific requirements for one or the other they are clearly identified. While IRP 22 is specifically meant to deal with MPD and UBD, the prevalence of RMD warrants some discussion within the context of IRP 22.

The following documentation has been included for RMD:

- A process flow diagram (see Appendix F: Process Flow Diagrams)
- An Operations Matrix (see 22.8.5.1 RMD Operations Matrix)

A checklist of information and procedures to discuss when the equipment is provided and/or used for a new well (see Appendix H: RMD Checklist).

22.2 Definitions and Regulations

22.2.1 Definitions

A Piping and Instrumentation Diagram/Drawing (P&ID) is a detailed schematic of the intended RMD/MPD/UBD rig up and integration with the conventional drilling plan. It is typically negotiated and hazard assessed between the RMD/MPD/UBD Service Provider, the Drilling Contractor and the Operator's design personnel.

Process Flow Diagram (PFD)

IRP 22 defines a Process Flow Diagram (PFD) as a **simplified** schematic of the site-specific P&ID to show the flow paths and equipment involved in the operations.

Due to the complex nature of P&ID diagrams, IRP 22 does not provide P&ID samples. Sample PFDs are provided (Appendix F) and IRP 22 purposely identifies when a P&ID is required or a simpler PFD can be used throughout the document.

RMD/MPD/UBD flare line

In well control terminology the line going from the mud gas separator to the flare line or system could be referred to as vent line. In IRP 22, this line in the RMD/MPD/UBD system is referred to as the RMD/MPD/UBD flare line.

Note: For the purposes of this IRP, any drilling operation that does not meet the definitions of RMD, MPD, or UBD is considered conventional drilling.

22.2.2 Regulations

The following are referenced throughout this IRP.

IRP 22 covers planning, equipment and operational practices related to RMD, MPD and UBD onshore operations in Western Canada. Many sections reference Alberta legislation and regulation but local jurisdictional regulations must always be consulted. A list of provincial resources is provided in Appendix K: References and Resources.

IRP 22 also makes extensive reference to two API standards documents. They are abbreviated throughout the document as follows:

1. API RP 92M: API Recommended Practice 92M – Managed Pressure Drilling Operations with Surface Back-pressure
2. API RP 92U: API Recommended Practice 92U – Recommended Practice for Underbalanced Operations

Complete references for these documents can be found in Appendix K: References and Resources.

The following topics related to planning of the operation are covered:

- Project Management
- Hazard Identification and Risk Assessment
- Well Parameter Review
- Well Control
- Process Flow Diagrams
- Engineering Requirements for High-Risk Scenarios
- Considerations for the Environment and Public
- Minimum Recommended Experience and Training

The equipment sections address equipment items and systems. They present recommendations to minimize risk and maximize operability for high-risk MPD/UBD concerns. The following topics are covered:

- Mechanical Wellbore Integrity
- Well Control Equipment
- Surface Circulating System
- Drill String and Drilling Rig

The operational practices sections contrast the differences between conventional and MPD/UBD operations, provide definitions and discuss high-risk HSE scenarios from the Risk Register. The following topics are covered:

- Wellsite Safety
- Operational Procedures
- Unplanned Operations or Events
- Other Operations (Air Drilling, Coiled Tubing)

RMD/MPD/UBD operations utilize different equipment and practices than conventional drilling and have different risk considerations. The risks, hazards and mitigating actions need to be clearly understood by all personnel involved in planning and executing the operation. Table X provides a list of recommended practices and specifications related

to MPD equipment. This list is provided for reference purposes only and is not intended to represent a complete list of applicable requirements. The entity responsible for the operation is responsible to ensure compliance with all applicable jurisdictional regulations and requirements governing the design, manufacturing, inspection, servicing, and operation of MPD equipment.

Table 30. MPD-Related Recommended Practices and Specifications

Sub-Component	Equipment	Document Number	Document Name	Scope of the Document
MPD Manifolds	Choke Valve	API Spec 16C	Specification for Choke and Kill Systems	Requirements for design, manufacture, and testing of choke and kill equipment used in drilling well control systems.
	Valves	API Spec 6D	Specification for Pipeline Valves	Requirements for design, manufacturing, testing, and documentation of pipeline valves (gate, plug, ball, check) for pipeline systems.
	Pipework	API Spec 16A	Specification for Drill-Through Equipment	Requirements for blowout preventers (BOPs) and related well control equipment used in drilling operations.
		API Spec 16C	Specification for Choke and Kill Systems	Requirements for design, manufacture, and testing of choke and kill equipment used in drilling well control systems.
		ASME B31.3	Process Piping	Requirements for design, materials, fabrication, testing, and inspection of piping systems in process plants.
		API RP 7HU1	Safe Use of 2-inch Hammer Unions for Oilfield Applications	Requirements for design and manufacturing of rotary drill stem handling tools.
		API RP 14E	Recommended Practice for Design and Installation of Offshore Products Platform Piping Systems	Requirements and guidelines for the design and installation of new piping systems on production platforms located offshore. Generally used to calculate erosional velocities in pipelines.
		API Spec 7HU2	Oilfield Hammer Unions	Inspection, maintenance, and recertification requirements for drill stem handling tools.
	Flanges	API Spec 6A	Specification for Wellhead and Christmas Tree Equipment	Requirements for wellhead, tree equipment, and associated components used in oil and gas production.
		ASME B16.5	Pipe Flanges and Flanged Fittings	Dimensions, tolerances, materials, marking, and testing of pipe flanges and flanged fittings.
Rotating Control Device (RCD)	Rotating Control Device (RCD)	API Spec 16RCD	Specification for Rotating Control Devices	Requirements for rotating control devices used in drilling operations for pressure control.
Miscellaneous	Sensors, Gauges and Flow Meters	API RP 500	Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities	Classification of hazardous locations for electrical installations in petroleum facilities.
		API RP 505	Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities (Zone System)	Hazardous area classification using the Zone system for petroleum facilities.
	Pressure Relief Valve (PRV)	ASME section XIII	Rules for Overpressure Protection	Requirements for overpressure protection devices, including certification and capacity testing.

Sub-Component	Equipment	Document Number	Document Name	Scope of the Document
		API Standard 520	Sizing, Selection, and Installation of Pressure-Relieving Devices	Guidelines for sizing and selection of pressure relief valves in refinery and petrochemical services.
		API Standard 521	Pressure-Relieving and Depressuring Systems	Design guidance for pressure relief and flare systems.
		API RP 576	Inspection of Pressure-Relieving Devices	Recommended practice for inspection, testing, and maintenance of pressure-relieving devices.
		AB-506	Inspection and Servicing Requirements for In-Service Pressure Equipment	Alberta regulatory requirements for inspection and servicing of in-service pressure equipment.
	Non-Return Valves (NRV) - Drill string valves)	API Spec 7V	Specification for Rotary Drill Stem Valves	Requirements for drill stem safety valves and related components.
		API Spec 7NRV	Specification for Non-Rotating Drill Stem Valves	Requirements for non-rotating drill stem safety valves.
	Sour Environments	MR 0175/ISO 15156	Materials for use in H2S-containing environments in oil and gas production	Provides general principles for selection of cracking-resistant materials
	Hoses	API Spec 17J	Specification for Unbonded Flexible Pipe	Requirements for design, manufacturing, and testing of unbonded flexible pipes for subsea applications.
		API Spec 17K	Specification for Bonded Flexible Pipe	Requirements for bonded flexible pipes used in offshore production systems.
		API Spec 7K	Specification for Drilling and Well Servicing Equipment	Requirements for drilling and well servicing mechanical equipment.
Mud Gas Separator (MGS)	Mud Gas Separator (MGS)	ASME Boiler and Pressure Vessel Code (BPVC)	ASME Boiler and Pressure Vessel Code – Section VIII, Division 1	ASME BPVC requirements for pressure vessels.
		API Spec 12J	Specification for Oil and Gas Separators	Requirements and recommendations for the process design of pressure-vessel-based gas–liquid and gas–liquid–liquid separators.
		IOGP STA035-MGS	Mud Gas Separator Design and Operating Recommendations	Guidelines for design and operation of mud gas separators for well control and gas handling.
Others*	Others*	API RP 92M	Recommended Practice for Managed Pressure Drilling Operations With Surface Backpressure	Operational guidelines for surface back-pressure MPD applications. Contains general guidelines on equipment design, selection and operation
		API RP 92U	Recommended Practice For Underbalanced Operations	Operational guidelines for underbalanced drilling (UBD) applications. Contains general guidelines on equipment design, selection and operation
		Norsok Standard D-010	Well Integrity in drilling and well operations	Defines the minimum functional and performance-oriented requirements and guidelines for well design, planning and execution of well operations with focus on well integrity. Contains some equipment-related guidelines.

*Refers to operational standards that contain sections with recommended equipment design guidelines

Regulations for Alberta include the following:

- Directive 036: Drilling Blowout Prevention Requirements and Procedures
- Directive 056: Energy Development Applications and Schedules
- Directive 060: Upstream Petroleum Industry Flaring, Incinerating and Venting
- Directive 071: Emergency Preparedness and Response Requirements for the Petroleum Industry

22.3 Project Management

Managing risk involves managing events within known and acceptable limits. Potential risk is unpredictable without knowledge of, or investigation into, the range of events which could occur. Effective well design is dependent on thorough analysis of the well parameters. Experienced well designers are aware of the possibility of uncertainty, unpredictability and change and draw on lessons learned from previous operations. Good well design incorporates a plan for a range of possibilities to ensure equipment and operational requirements are capable of safely executing the full spectrum of possibilities in the well program.

Operations can be conducted confidently with assurance and responsibility under the following circumstances:

- All parties are in acceptance of the operation and understand the objectives and associated risks.
- Measures to take control or eliminate hazards are in place.
- Procedures and equipment are in place to address risk and unscheduled interruptions.

IRP If RMD/MPD/UBD operations are anticipated they should be planned for with participation from both the operator and service provider.

IRP A project management process that includes contingency planning should be used for all RMD, MPD and UBD operations.

Refer to Appendix B for a sample project management process for planning and execution.

22.3.1 Planning

Thorough planning is required to competently execute RMD/MPD/UBD risk management techniques. This includes research on individual components used in the circulation system and careful review of operational activities.

The following should be conducted/prepared during the planning stage for every RMD/MPD/UBD project to ensure that operations can be carried out safely and effectively:

- Review of lessons learned for specific areas
- Technical feasibility studies/analysis
- Process Hazard Analysis & Emergency Response Plan (ERP) (see Appendix C: Hazard and Risk Assessment Process)

- Detailed engineering design and well modeling
- Rig survey and tie-in of equipment
- MPD/UBD drilling program with procedures. For RMD operations refer to the RMD Equipment Checklist in Appendix H. For rented MPD equipment refer to the MPD Equipment Checklist in Appendix I.
- Selection of qualified MPD/UBD personnel. For RMD the equipment is rented and managed by onsite personnel.

IRP **All stakeholders shall be included in discussions, negotiations and preplanning activities of RMD/MPD/UBD operations to ensure all concerns are addressed and all roles and responsibilities are clearly identified.**

IRP **Cohesive plans shall be in place to ensure compliance with all jurisdictional regulations (e.g., lifting sling certifications, equipment inspections and certifications, etc.).**

Integration of each organization's safety procedures is imperative to avoid onsite conflicts and delays. Teamwork is important for risk management on the MPD/UBD wellsite.

IRP **Activities relating to occupational health and safety of all contractors on site must be coordinated by as per local jurisdictional OH&S regulations. In Alberta and B.C. this must be coordinated by the operator.**

IRP **A site/pad-specific P&ID and PFD shall be created and posted at the rig site for each RMD/MPD/UBD rig up and included in all site-specific drilling programs. A rig-specific P&ID and PFD may be used for integrated equipment or if the rig-up is consistent between pads or sites.**

IRP The P&ID should be risk assessed prior to implementation to ensure any noted hazards are reviewed and mitigations developed for known and anticipated problems (see 22.4 Hazard Identification and Risk Assessment).

22.3.2 Non-Routine Operations

Non-routine operations such as natural gas recovery to pipeline/facilities or drilling with natural gas may occur during MPD/UBD operations.

IRP **A comprehensive risk assessment shall be completed for all non-routine operations.**

Those with experience in these areas are strongly encouraged to share their experience with industry (see Appendix C: Hazard and Risk Assessment Process for details).

Unanticipated problems may be encountered during the execution of MPD/UBD programs. Activities not originally thought to be required in the well plan may be required. Some examples are as follows:

- Slick, braided or electric wireline operations may be required to obtain wireline directional surveys or to remedy stuck pipe, leaking downhole NRVs, leaking drill strings or plugged strings or resolve other issues.
- Drill strings may become plugged. This may require hot tapping to remove trapped pressure and allow safe removal of tubulars from a pressured wellbore.
- Adverse reactions in the drilling fluid system may cause difficulties. This may require additional additives to address unanticipated problems.

IRP All details of the specific remedial operations should be risk assessed including the following:

- The use of a wireline unit or other specialized equipment
- Specific chemicals required
- Detailed procedures required
- Additional associated personnel required

IRP Mitigations shall be put in place prior to execution for any hazards associated with unscheduled activity.

The details are documented in work instructions and review with personnel in advance to ensure all personnel and involved organizations are aware of the risks and contingency plans for the work.

IRP Influx management using MPD equipment is considered non-routine and should be included in the risk assessment.

22.3.3 Project Approval

IRP The RMD/MPD/UBD project plan and the application to the appropriate regulator shall be signed off by a representative authorized by the operator.

The sign-off confirms that all requirements of this IRP have been addressed in the plan and that the plan was developed with input from qualified technical experts with valid credentials.

IRP The RMD/MPD/UBD wells shall be licensed based on the local jurisdictional regulations.

22.4 Hazard Identification and Risk Assessment

The identification of potential hazards and assessing their risk is a fundamental part of planning. Proper hazard and risk assessment provides the following:

- Protection for workers
- Protection for the environment
- Protection for assets
- A basis for well engineering
- A reduction in non-productive time (NPT)
- Regulatory Compliance

RMD/MPD/UBD operations differ from conventional drilling, usually including additional surface and subsurface equipment and a more complex design. These differences are a key risk control/mitigation challenge for RMD/MPD/UBD operations. There are numerous hazards, all with a potential to give rise to unwanted consequences, which are unique to RMD/MPD/UBD operations.

IRP All hazards shall be identified and assessed for risk as part of the project planning process.

IRP Each hazard shall have a complete, suitable and sufficient risk assessment that outlines the measures required to ensure the risks for each hazard are adequately controlled or mitigated.

ISO standards define risk as “the combination of the probability of an event and its consequences”. For MPD/UBD operations the consequences of events (i.e., hazard scenarios) can be understood but the probability of occurrence is much more difficult to predict and quantify. The IRP 22 Hazard and Risk Assessment Process outlined in Appendix C uses a qualitative approach to determine risk-severity based on collective industry expert experience. This should be considered the minimum level of risk assessment required.

IRP Where there is no relevant best practice, or the existing best practice is considered by the site-specific risk assessment to be insufficient or inadequate, suitable control measures should be formed by further risk assessment.

As control measures are introduced, the residual risks may fall so low that additional measures to reduce them further are likely to be grossly disproportionate to the risk reduction achieved, though the control measures should still be monitored in case the risks change over time.

IRP **There are some risks from certain activities, processes or practices that are unacceptable, regardless the benefit. These activities shall be ruled out unless the activity or process can be modified to reduce the associated risks to a level that is As Low As Reasonably Practicable (ALARP).**

Note: For the purposes of all IRPs, ALARP is the default risk management principle for major accident hazards, well control, process safety and operational risks. Where applicable legislation, regulation or recognized technical standards specifically require ALARA, including for occupational hygiene, radiation, NORM or chemical exposures, ALARA applies.

NPT events often lead to unplanned well operations and, possibly, inappropriately risk-assessed hazard scenarios. The IRP 22 Hazard and Risk Assessment process includes a required risk analysis of potential NPT events, consideration for NPT event avoidance and subsequent contingent well operations/procedures to return the operation back to the original operational plan.

IRP 22 suggested risk assessment process is not the only method available to evaluate hazards. It is intended as a starting point for those service providers with no process.

The IRP 22 Hazard and Risk Register (Risk Register) was developed to provide a starting point for assessing the hazards associated with RMD/MPD/UBD operations. The Risk Register is intended to be used as follows:

- To facilitate operational planning by identifying potential hazards and mitigations in RMD/MPD/UBD scenarios.
- To establish a baseline and industry standard for risk tolerance.
- To provide a framework for establishing contingency planning.
- To initiate a process to gather, review and append items for an industry Risk Register.

The Risk Register was structured for RMD/MPD/UBD industry-wide use so it may not fall entirely within an organization’s policy for hazard and risk analysis. However, the information in the Risk Register can easily be used (or adapted) to populate an organization’s internal hazard register.

The Risk Register can also be a tool to facilitate effective communication during planning. It can be used as a discussion and documentation tool at a meeting of all stakeholders to identify known hazards, list consequences and document steps to

mitigate the hazards. As each known hazard is identified, planners can consult the Risk Register to define appropriate actions and assign the responsible parties. The IADC MPD/UBD HSE guidelines provide details on conducting HAZIDs/HAZOPs for MPD/UBD operations.

IRP The completed Risk Register should be made available to all parties on location.

IRP RMD/MPD/UBD service providers should have an established risk assessment process to evaluate the risks associated with RMD/MPD/UBD operations.

Industry-side guidance is available to support the coordination of health and safety at the worksite. See the International Association of Oil and Gas Producers (IOGP) 423-02 Guide to Preparing HSE Plans and Bridging Documents.

22.5 Well Parameter Review

The first step of the well parameter review is to gather pertinent information to make knowledgeable planning decisions and reduce the potential for unexpected hazardous situations. It is important to focus preliminary planning efforts on the following types of questions:

- Has the well (or wells) been identified as a good RMD, MPD or UBD candidate?
- Do the operations involve any additional challenges (e.g., Geothermal, HPHT, SAGD etc.)?
- For UBD, is lift gas required? If so, what type of gas and how will it be arranged?
- Have drilling fluids been evaluated to address, as thoroughly as possible, the specific requirements for all stakeholders?
- If using an existing design of a conventionally drilled well, is the casing design aligned with the pore and fracture pressure profiles?
- Have casing strings and wellhead assemblies been selected based on maximum shut-in potential and casing wear?

Once these preliminary decisions are made the following, at minimum, can be completed:

- Conduct flow modeling to determine if it is technically feasible to drill the well and establish an operating envelope (UBD) for the project or remain within a desired drilling pressure window (MPD).
- Estimate the range of possible operational well behaviours and then determine equipment specifications and procedural requirements from those behaviours.
- Evaluate each well design for risk. Additional resources may be required to create safe working conditions.

IRP The planning process should include a review of the well design, well schematic and the following parameters:

- Wellhead Pressure
- Drilling Window (Pore Pressure/Fracture Gradient)
- Flow Rate Potential
- Drilling/Produced Fluids
- Sweet or Sour Wells
- Wellbore Integrity

- Temperatures
- Hydrate Risks
- Erosion and Corrosion

22.5.1 Well Schematic

IRP All hydrocarbon well license applications in Canada must include a well schematic prepared by the well operator.

The well schematic represents the core of all offset information, hazard assessments, drilling practices, due diligence and best judgment for a very specific area.

As per AER Directive 36: Drilling Blowout Prevention Requirements and Procedures, “A ‘STICK’ diagram is a well data information sheet specific to the drilling operation of a well (obtained from researching offset well records). It must provide the appropriate onsite personnel (e.g., licensee, rig manager, driller) with sufficient well control information to drill the well and must be posted in the doghouse. The appropriate on-site personnel must review and understand the information provided in the STICK diagram prior to drilling out the surface casing shoe or prior to the commencement of drilling operations with a diverter system.”

IRP The well schematic or stick diagram must be posted on site (usually in the doghouse).

The following information would be also valuable during the MPD/UBD design phase:

- Fracture gradients
- Temperature at final true vertical depth
- Wellbore stability limits
- Potential H_2S and well type related to H_2S
- Other pertinent well information (e.g., MPD, UBD)

The operator may add any other technical information related to the Well Construction Program in order to increase operational safety, reliability and efficiency.

IRP The well schematic shall not be considered a substitute for other mandatory documents such as the following:

- Detailed Well Construction Program (Drilling Program)
- Directional Drilling Program
- Drilling Fluids Program
- Cementing Program

- MPD/UBD Program. For RMD operations refer to the RMD Equipment Checklist in Appendix H.
- Site Specific Emergency Response Plans
- Wireline logging and/or data acquisition plan (coring, samples etc.)
- Well Completion Program
- Well Testing Program

IRP **All on-site personnel (operators, contractors and sub-contractors) shall review and understand the information provided in the well schematic prior to spud.**

IRP **H_2S specific operations and safety must be reviewed prior to penetration of a sour zone.**

See IRP 01: Critical Sour Drilling for more information about sour operations.

IRP **The well schematic shall be reviewed with all personnel on site before the start of RMD, MPD or UBD operations with emphasis on the communication system, the RMD/MPD/UBD equipment and operational procedures to be used.**

The well schematic is the basis of the scope of work to drill, complete and test the well safely, efficiently and reliably.

IRP **If for any reason the scope of work changes, in whole or in part, the applicable local jurisdictional regulator must be notified. The well schematic and other impacted programs and procedures may need to be modified and reviewed at handover/tour reviews accordingly.**

Drilling factors that could change the scope of work include new pressure regimes, adverse hole conditions or H_2S reported in a non-H_2S assessed area.

22.5.2 Wellhead Pressure

MPD/UBD processes create greater pressure variation throughout the annulus side than seen with conventional drilling. Stability in terms of wellhead pressure and inflow rate is one objective of all MPD/UBD flows. The well should be designed to be able to withstand the maximum predicted surface pressure (MPSP) and maximum anticipated surface pressures (MASP) during the life of its operation. For re-entry projects in particular, consider the effect higher pressures may have on the existing casing string or on the wellhead. Evaluate the casing string integrity in the early stages of the design phase of the project.

IRP MPD hydraulic sensitivity study simulations should be performed to ensure the wellbore pressure will be maintained at or slightly above the estimated pore pressure and within the expected drilling pressure window. Consideration should be given to surface equipment limitations (see 22.8.5.2 MPD Operations Matrix).

IRP UBD multiphase simulations should be performed to define injection rates for liquid and gas. Preference should be given to those combinations that offer maximum flexibility to maintain bottomhole pressure within the target window, maintain hole cleaning and maintain reasonable wellhead pressures as per the Operations Matrix for the well (see 22.8.5.3 UBD Operations Matrix).

There is no way to intentionally hold pressure in RMD operations because there are no surface chokes included in the operation.

22.5.3 Drilling Window

Drilling window (also commonly referred to as mud weight window) considers pore pressure, fracture gradient and wellbore stability limits (if known).

Knowledge of pore pressure is important to well design. If pore pressure is unknown the offset pressure data should be used as a minimum while planning. Always ensure planning incorporates the maximum expected pore pressure.

In the planning phase pore pressure and fracture gradient values are based on data from offset wells. Take new measurements whenever there is a change in the formation pressure profile. These measurements can be taken by conventional and dynamic flow checks, dynamic formation integrity tests (FITs) and/or dynamic leak off tests (LOTs).

In horizontal wells, especially extended reach drilling (ERD) wells, pressure designs should consider that as measured depth increases the bottomhole equivalent circulating density (BHECD) will increase, which may potentially exceed the drilling window. Drilling fluid weight and/or surface backpressure (SBP) may need to be adjusted to maintain the intended drilling window.

A FIT test is recommended to ensure the accuracy of the operations matrix (see 22.8.5 Operations Matrix). At minimum, have a FIT test performed at the shoe once drilled out.

22.5.3.1 MPD Operations

It is important to identify/define the lower and upper limits of the drilling window (hole stability limit, pore and fracture pressures, and any other necessary parameters) when designing MPD operations. An incorrect (low) pore pressure may result in unwanted flow from the formation or hole collapse. Likewise, an incorrect (higher) fracture pressure may result in unwanted fluid loss into the formation. Underestimating pore pressure can result in insufficient capacity of surface equipment to handle influx circulation operations.

Knowledge of pore pressure is advantageous for MPD operations. If pore pressure is unknown, MPD operations can assist in ascertaining the downhole environment while drilling.

IRP Pressure offsets within the area should be used to understand the pressure profile and ensure proper equipment selection.

If offset data is limited or unavailable, refer to the maximum pressure the wellbore is designed for as per the MPD Operations Matrix (see 22.8.5.2 MPD Operations Matrix).

The pore pressures used during planning may not be the pressures experienced during drilling. Fluid density and wellhead pressure can be adjusted to reflect the actual well pressure profile.

In MPD operations, the equivalent drilling fluid density is maintained at or above pore pressure to avoid any influx. At the same time, it has to be kept below the fracture gradient to prevent losses of drilling fluid into the formation.

There may be cases where breakout pressure is higher than pore pressure or breakdown pressure is lower than the fracture gradient. In these situations, the drilling window needs to be defined by hole stability pressure (breakout pressure). See the Glossary for definitions for breakout and breakdown pressure.

Performing dynamic FIT/LOT/flow checks can help define the drilling window if the drilling window is unknown or requires verification (especially in exploration wells).

IRP The following factors should be considered during MPD operations, as they could affect the ability to operate within the planned system limits and may require operations to be stopped or evaluated before further investigation.

- Significant changes in drilling fluid properties (e.g., rheology, density).
- Disruption in communication between the MPD operator and driller.
- Changes in the tripping plan or connection procedure which can impact swab and surge effects.
- Kick detection methods and mitigating actions, such as when to transition to secondary well control.
- Reduction in available drilling fluid volumes.
- Changes to the defined well barriers.
- Unexpected events that could affect the ability to secure the well or operate the MPD system within the planned limits.

22.5.3.2 UBD Operations

IRP Pore pressures should be sampled over a range to ensure accuracy.

If actual reservoir pressure is only marginally lower than predicted, additional gas injection may be required to achieve an underbalanced state and liquid injection rates may be compromised. This can affect the ability to remain within tolerable drilling rates or hole cleaning limits. A much lower pressure can result in equipment limits that require more gas or a lower pump rate than possible with the equipment on site. Subsequent logistics and equipment supply issues can severely disrupt programs and costs.

IRP When the plan includes penetration of multiple potentially productive sections, each section shall be reviewed to ensure the difference in pore pressures is manageable and crossflow can be prevented.

A large difference in pore pressures can cause competition between the zones (i.e., it may be difficult to keep one of the zones underbalanced because of competition from the other). A difference in pore pressures can also lead to excessive zonal production, high pressures and create high surface rates (and potential surface storage problems).

Depending on the situation, the productivity of the zones can be a factor in the decision to drill UBD.

Fracture pressure is usually not relevant for UBD operations. However, knowing and understanding the fracture pressure gradient behaviour may improve planning, particularly with shallow casing shoes. Wellbore stability can be a limiting factor.

In UBD operations equivalent drilling fluid density is kept below pore pressure (assuming there are no hole instability issues). Ensure a single-phase fluid is used for integrity testing.

22.5.4 Flow Rate Potential

The flow rate potential of the productive section is a function of its permeability, fluid types and reservoir pressure. Formation fluids enter the well when a permeable section is penetrated, thus leading to the potential hydrocarbon production while drilling. For this reason, the drilling rig and surface equipment needs to be sufficient to handle possible production rates in UBD operations.

IRP Hydraulic simulations should be performed to determine optimal injection flow rates.

Simulation results drive the specifications for application type, piping, separation, chokes, monitoring/measurement and fluid storage systems. Planning for a range of possible permeabilities and reservoir pressures can ensure the objectives are met safely even if there are inaccuracies in the assumed properties.

22.5.4.1 MPD Operations

MPD operations are designed to ensure formation fluids are not produced to surface. The equivalent mud weight (EMW) achieved while drilling is designed to be greater than the formation pore pressure and remain within an MPD drilling window, thereby ensuring formation fluids are not produced.

IRP Appropriate equipment and procedures shall be in place to prevent formation fluids from entering the wellbore and to restore MPD objectives.

Depending on the set MPD objectives, drilling fluid weights used may result in a hydrostatic pressure less than the formation pressure. The addition of choke pressure is used to balance the bottomhole circulating pressure (BHCP) to the formation pressure, thereby ensuring formation fluids are not produced while maintaining all parameters within the MPD Operations Matrix (see 22.8.5.2 MPD Operations Matrix).

IRP If formation fluids enter the wellbore and exceed the MPD Operations Matrix limitations (including kick intensity), flow must be diverted to the rig and controlled using the rig's well control system.

MPD allows for opportunities to evaluate the formation during drilling by performing a Dynamic Pore Pressure Test (DPPT) using a hydrostatically underbalanced drilling fluid system. This involves reducing the applied surface backpressure gradually until a small influx from the reservoir is observed, then increasing the applied surface backpressure until the planned overbalanced condition is achieved.

IRP If a DPPT is planned, suitable equipment and procedures shall be in place to safely perform the test within the well's MPD Operations Matrix.

Suitable equipment could include the following:

- A dynamic flow meter
- A larger MPD separator
- Adequate surface storage capability
- A larger MPD flare stack
- An appropriately sized MPD choke manifold
- Accurate data capture (with recorded graph)

22.5.4.2 MPD Backpressure Management

MPD techniques may use a lighter drilling fluid in combination with annular frictional pressure and applied surface pressure to produce circulating bottomhole pressure at or above the reservoir pressure. Reservoir inflow is prevented by keeping bottomhole pressure at or above reservoir pressure.

IRP To make MPD connections, a higher annular pressure should be retained to compensate for the loss of annular friction. Many MPD wells include a Pressure While Drilling (PWD) tool in the BHA to provide feedback on bottomhole pressure changes as choke pressure increases. In the absence of a PWD tool to observe and monitor bottomhole pressure changes, calibrated hydraulics simulators may be used to determine retained pressures on connections.

IRP A written procedure should be in place to manage the transition from static to dynamic states and vice versa. Once operations have started, the bottomhole pressure record and surface flow/pressures should be reviewed to determine if improvements in the process are possible. Modified procedures should be risk-assessed prior to execution to ensure the changes do not cause any additional risk. If they do, mitigations should be developed before implementing the new procedure.

The MPD technique to control bottomhole pressure by combining wellhead pressure, annular friction and (reduced) drilling fluid density can result in the casing seat being exposed to pressures that are higher than in conventional overbalanced drilling operations. Although the intent is to use MPD techniques, well control incidents may still occur. Well control procedures are dependent on the MACP.

Where practical, well programs need to allow for FITs to a deemed appropriate surface backpressure or LOTs to determine the magnitude of MACP.

IRP Prior to tripping out of the hole with MPD equipment, procedures shall be prepared to address changes in wellbore pressures when less-than-kill-weight drilling fluid is utilized, including use of surface backpressure as a trip margin to mitigate swabbing of an influx. Swab and surge calculations shall be accounted for in these procedures.

This may involve first displacing a volume of kill weight drilling fluid prior to tripping or could include stripping (i.e., pulling the drill string through a closed RCD) to some level before displacing to kill weight fluid. Exercise reasonable care when stripping pipe in or out of the hole to compensate for swab and surge effects. Follow best tripping practices by monitoring the amount of drilling fluid added to the well to replace the displacement volume of the drill string/BHA.

Unplanned shutdowns may cause significant issues for MPD operations. Review potential disruptions and discuss the appropriate actions and procedures in safety meetings prior to starting new activities to ensure crews understand what to expect and how to respond. Response and reaction times can be greatly improved by reviewing procedures and roles related to unplanned shutdowns and by ensuring crews are prepared and have practiced the procedures for unscheduled events. Refer to 22.17.1 Unplanned Shutdowns for more information.

22.5.4.3 UBD Operations

UBD operations are designed from the start to intentionally produce the formation fluids while drilling. Flush production refers to the initial high production rate exhibited by a permeable feature when first encountered in a UBD operation. The high initial flow rate (as a result of the underbalanced margin) lessens with time but the increase in overall flow rate can be significant.

Failure to provide a system with sufficient throughput to deal with flush production events can result in significantly more time spent circulating and regaining parameters to operate within the green zone of the specific Operations Matrix (see 22.8.5.3 UBD Operations Matrix).

IRP The separation and pressure control equipment shall be capable of dealing with fluctuations in the overall flow rates.

A process system with insufficient flow capacity can result in inadequately tested wells. For example, a flare system with insufficient throughput capacity can restrict flow rates to the point that essential reservoir information cannot be derived. Inability to achieve a reasonable flow rate may be dependent on other issues such as liquids storage capacity, separation capacity or excessive erosion hydrate formation (including regulatory restrictions/flare limitations).

22.5.5 Drilling/Produced Fluids

Knowledge of all potential drilling/produced fluids involved in the operation is critical to prevent fluid incompatibilities and operational issues.

22.5.5.1 Drilling Fluids

IRP The successful selection and management of drilling fluid for MPD/UBD operations shall consider the following to establish a well classification for risk assessment:

- IADC Well Classification (see Well Classification in the Glossary).
- IADC Application Category (see Application Category the Glossary).
- IADC Drilling Fluid System (see Drilling Fluid Systems in the Glossary).
- The purpose and objectives of the MPD/UBD program.

Equivalent circulating density (ECD), compatibility and hole stability are important concerns for the drilling fluid selected for RMD/MPD/UBD.

Note: Drilling fluid system adjustments that require increasing the drilling fluid weight to combat hole stability problems can compromise the surface separation equipment (e.g., can increase erosion).

IRP Drilling fluid design should consider the following:

- Drilling fluid compatibility with the formation lithology and formation fluids
- Geomechanical study of the formation
- Fluid density changes with temperature
- Hole cleaning issues
- The effects of corrosion
- The use of down hole tools
- Health and safety
- Environmental and fluid disposal
- Rheological effects (i.e., surge/swab)
- Produced fluid concerns (i.e., logistics, handling, contamination, safety)
- Elastomer compatibility
- Separation issues at surface (e.g. emulsions, foaming, line/instrumentation blockages, etc.)

See Considerations for Drilling Fluid Design in Appendix D: Drilling Fluids for more detail.

A decision tree process based on the purpose and objectives of the program and the drilling fluid design considerations can be helpful (see Process for Drilling Fluid Selection section in Appendix D: Drilling Fluids).

22.5.5.2 Circulating Fluids

IRP Circulating fluids for MPD/UBD wells should be tailored for the well or reservoir requirements.

This may include the use of physical or chemical constituents to minimize formation damage. Risk assessment should include a review of the drilling fluid(s) planned for the operation.

Operational problems such as high torque and drag and difficulty working weight to bottom when sliding can be improved with the addition of chemical lubricants.

Foaming sometimes occurs in the returns from UBD wells and can be addressed by adding defoaming chemicals. Perform pilot testing prior to adding any additive to the circulating system to understand compatibility and verify properties are as designed.

When using nitrogen as injection gas there is the possibility of the gas invading exposed elastomers (generally at pressures above 7000 kPa). Nitrogen invasion can lead to creation of delaminating gas bubbles and dimensional swelling in elastomers when

pressures are reduced. Small incidents, such as swelling of elastomer centralizers on measurement while drilling (MWD) probes, may make removal problematic. Mud motor stator elastomers can swell rendering rotor movement impossible. Reinitiating the (downhole) pressure condition which caused the invasion can collapse the bubbles. A strategy with respect to stator life versus injected gas (and drilling fluid) may be considered. Elastomer type and replacement frequency may change depending on conditions.

Steerable downhole turbines are available which can be tailored for the specific fluid injection rates planned and have no problematic exposed elastomers.

Additional information can be found in the following resources:

- IRP 04: Well Testing and Fluid Handling
- IRP 14: Non-Water Based Drilling Fluids
- API RP 92U
- IADC Fluid Selection for Underbalanced Drilling Operations

22.5.5.3 Kill Fluid

RMD operations use a single-phase drilling fluid system.

IRP For RMD there should be adequate weighting materials to achieve static overbalance with the current hole volume plus a trip margin.

IRP For MPD operations utilizing a single-phase drilling fluid system, there should be adequate weighting materials to achieve static overbalance with the current hole volume plus a trip margin. For multi-phase drilling fluid systems, the requirements noted above for UBD apply.

IRP For UBD operations the volume of surface kill fluid readily available should be as follows:

1. If the liquid phase of drilling fluid being used is of sufficient kill weight density, then 100% of the hole volume.
2. If the liquid phase of drilling fluid being used is not sufficient kill weight density, then 150% of the hole volume.

22.5.5.4 Reservoir Fluids

The potential for any up-hole nuisance gas above the target pay zone should be managed in accordance with the IRP 22 Project Management Process (see Appendix B: Project Management Process) and risk assessment.

Reservoir fluids start to flow into the wellbore as soon as the drill bit penetrates a reservoir with pore pressure higher than bottomhole pressure. It is important to ensure the drilling fluid is compatible with the reservoir fluid.

RMD is used for managing nuisance gas only. Any increase in fluids production should lead to a change in technique (i.e., MPD or UBD).

In MPD operations the aim is to stay above pore pressure and avoid having any formation fluid in the wellbore. The drilling fluid has to maintain a stable rheology if reservoir fluid enters the wellbore and mixes with the drilling fluid. Consequences of incompatible reservoir and drilling fluids can include foaming/de-foaming, the inability to clean the hole and emulsion formation.

In UBD operations the stabilized multiphase flow regime in the well prior to reservoir fluid entry will be adjusted once inflow is observed, without upsetting the circulating system or moving out of the UBD operating window already established.

22.5.5.5 Fluid Hazard Management

MPD/UBD operations frequently use oil-based drilling fluid systems to

1. reduce bottomhole pressure (lower fluid density reduces the need for injected gases) and/or
2. address formation damage or formation stability concerns.

Oil based fluids may be required in MPD operations for the following reasons:

- Formation stability
- Drillability
- High Pressure High Temperature (HPHT) situations

The presence of oil-based fluids on site creates additional risks that need to be assessed (see section 22.9 Environment and Public). It also creates operational risks due to gas solubility that may be detrimental to influx detection and circulation.

Well planners and operational personnel should refer to:

- IRP 04: Well Testing and Fluid Handling
- IRP 08: Pumping of Flammable Fluids
- IRP 14: Non-Water Based Drilling Fluids
- Energy Safety Canada Fire and Explosion Hazard Management Guideline

22.5.6 Sweet or Sour Wells

Most drilling systems do not tolerate sour fluids (H_2S). If the planned program is designed for sweet operations and sour gas is detected in the returns there will be a major impact on operations and operational safety.

For the purpose of these recommended practices, sour wells are those that contain an H_2S concentration greater than 0 ppm observed while drilling. Wells can be planned as sweet MPD/UBD with a sour MPD/UBD contingency plan put in place if sour gas is encountered.

IRP The RMD/MPD/UBD plan shall assess the risk of encountering sour formations and identify mitigating actions.

IRP Operations shall be designed and conducted to provide zero worker exposure and zero uncontrolled H_2S release if H_2S is anticipated.

A closed-loop system is defined as having the entire circulating system contained and not exposed to atmosphere. This would include additional surface equipment such as an enclosed cascading system, transfer pumps, H_2S scrubbers and scavengers.

IRP For potential sour MPD/UBD wells, all surface equipment shall be sour rated and NACE compliant, H_2S monitoring shall be in place and sour closed loop contingency plans shall be completed.

IRP A shift to a closed loop system shall be implemented when continuous sour returns are measured at surface that cannot be mitigated by scavenging or similar methods.

IRP A change management process that includes a risk assessment should be in place in the event that operations shift from an open system to a closed system.

IRP Procedures should be in place to ensure the section of the drill string from the connection to the top most float is purged of H_2S prior to breaking the pipe for a connection.

For MPD operations, surface backpressure or drilling fluid weight can be increased to avoid sour returns/gas to surface.

IRP Regardless of the concentration of H_2S, sour gas must NOT be released to atmosphere at any time and all efforts must be made to flare, scrub or sweeten the gas instead of venting.

IRP Produced fluids containing H_2S or drilling fluids contaminated with H_2S shall be stored in closed tanks or a tank system in which the H_2S

concentration is monitored in the fluid (and in the ambient air) and treated out completely with scavengers.

The choice of system should be based on a risk assessment with the primary purpose being to eliminate worker exposure to H_2S (and atmospheric venting) throughout the entire job, including minimizing confined space entry for tank cleaning considerations, monitoring fluid levels in closed tanks while drilling (avoiding spills), etc.

IRP **Local jurisdictional regulations must be reviewed to determine sour concentration limits and flare permit requirements.**

Note: In Alberta, a flare permit must be obtained from the AER if H_2S concentrations exceed five percent.

IRP **An analysis shall be completed to determine all the areas on location to be monitored for ambient H_2S concentrations.**

It is recommended that an air trailer, including a rescue-trained operator/technician, be on site with supplied air breathing apparatus in sufficient quantities for the minimum personnel requirements during well control operations.

Personal H_2S monitors are recommended for all personnel with potential for exposure to H_2S.

IRP **Personnel shall be trained in the appropriate use and maintenance of H_2S monitors.**

IRP **The sampling procedure for obtaining both drill cutting and well effluent samples shall follow the safety standby system as described in IRP 04: Well Testing and Fluid Handling.**

Note: Purging the sample catcher with nitrogen, sweet gas or propane is recommended.

IRP **The sour service equipment specification set out in IRP 04: Well Testing and Fluid Handling shall be referenced when selecting fluids handling equipment for drilling sour wells underbalanced.**

IRP **A pressurized tank or a tank truck equipped with a functional H_2S scrubber shall be used for the transportation of sour fluids off location. See IRP 04: Well Testing and Fluid Handling section on Tank Truck Loading for more information.**

For additional planning considerations see 22.7.6 Sour UBD System and 22.7.4 Sour MPD System.

Additional references for operations in sour gas are as follows:

- IRP 01: Critical Sour Drilling
- IRP 02: Completing and Servicing Critical Sour Wells
- IRP 04: Well Testing and Fluid Handling
- IRP 06: Critical Sour Underbalanced Drilling
- AER Directive 71: Emergency Preparedness and Response Requirements for the Petroleum Industry

22.5.7 Wellbore Integrity

Wellbore integrity needs to be sustained throughout the entire operation (i.e., during drilling, logging and when running and cementing casing). To understand what kind of forces the wellbore is exposed to, a decision needs to be made if the well will be drilled overbalanced, underbalanced or at the expected formation pressure. A geomechanical stability study may be performed to understand if the formation exposed to the reduced bottomhole pressures is capable of withstanding the stresses generated by the drilling process.

Permeable and porous sections are able to deplete pressure as field development progresses. Shale has no effective permeability and usually retains original pressure. Designing for an underbalanced borehole relative to the partly de-pressured pay section will see considerably higher underbalanced states in the shale which can cause hole collapse. Similar situations can occur with MPD.

The following can be considered when drilling RMD/MPD/UBD hole intervals or sections that require casing and cementing:

- Perform hole interval integrity testing at pressures equivalent to the planned casing cementing program to ensure the highest probability of a successful cementing operation and effective zonal isolation.
- Conduct an integrity test prior to running casing to ensure the planned cementing program is appropriate and well control risks have been addressed.

IRP Collapse loading on casing strings may be higher in MPD/UBD than in conventional drilling operations. These collapse loads should be considered during planning (i.e., consider the worst-case scenario and local jurisdictional regulations).

MPD operations commonly exhibit the following wellbore integrity conditions:

- Exposure of the wellbore to reservoir fluids (small quantities)
- Higher stresses on casing and cement sheath
- Dynamic surface pressures

UBD operations commonly exhibit the following wellbore integrity conditions:

- Exposure of the wellbore to reservoir fluids
- Higher stresses on formation, casing and cement sheath
- Reduced bottomhole pressure and temperature
- High and variable surface pressures
- High flowrates
- Full static reservoir pressure minus the gas gradient to surface (in some gas wells)

Note: Wellbore stability challenges in UBD operations increase for open hole formations.

The Well Barrier Envelope (WBE) needs to be considered as part of the well integrity review during RMD/MPD/UBD operations to ensure no uncontrolled flow of reservoir fluids is seen during drilling and completions operations. See 22.6.1 Barriers for more information about well barriers and the WBE.

22.5.8 Temperatures

Low temperatures, as can occur in the choke manifolds with substantial gas throughput, can impact the potential for erosion and hydrate formation. Refer to 22.5.9 Hydrate Risks for more information.

The bottomhole temperature has to be considered while drilling in high temperature wells as physical and rheological properties of the drilling fluids may change which can affect the ECD. Additional backpressure may have to be applied or drilling fluid weight increased to compensate for the effect of high temperatures on the drilling fluids. The surface equipment (e.g., RCD element/rubbers, elastomers, etc.) needs to be designed based on the bottomhole temperature and the potential high temperature fluid returns to surface. Surface cooling systems may be required.

IRP Thermal effects on hydraulic modelling and surface equipment temperature limitations should be taken into consideration during RMD/MPD/UBD planning. Equipment limitations and maintenance frequency should be monitored in extreme temperature environments.

22.5.9 Hydrate Risks

Hydrates are complex mixtures of gas-water solids which can form in areas of temperature and/or pressure decrease. Hydrates can completely block flow under certain conditions. Hydrates are typically only a concern when gas is produced from the wellbore and this is only the case when in an underbalanced state. Hydrates are not a concern for MPD operations.

Hydrate problems can impact the ability to obtain sufficient flow information. If there is a possibility for a combination of gas and liquid water, either as a result of production with the gas or from condensation as fluids transit the wellbore through the surface facilities, there is a possibility for hydrate formation even at temperatures significantly above 0 °C.

Mitigations for the effects of hydrates include, but are not limited to, the following:

- Use additional pressure drop stages instead of one stage pressure drop (e.g., use two chokes, one fixed and one variable).
- Use a dual-leg choke to allow alternate use if plugging occurs.
- Dissolve and or inhibit hydrate plugs using antifreeze (e.g., Methanol or Glycol based liquids).

  Note: Review safe work procedures with all personnel involved in handling and injecting any type of antifreeze. Methanol or similar hydrate treatment products such as glycols need to be checked for compatibility with all fluids used on site (as per 22.4.5 Drilling/Produced Fluids). The use of methanol requires a risk and hazard assessed in terms of personnel exposure, circulation system contamination, flammability and elastomeric seal impacts.

- Include a provision for supply, storage and use of specialty chemicals in the overall HSE plan. See the Energy Safety Canada Controlling Chemical Hazards (CCH) in the Oil and Gas Industry: Program Development Guide for more information.
- Installing line heaters for gas wells to allow preheating prior to a choke to ensure hydrate conditions cannot occur.

22.5.10Erosion and Corrosion

Corrosive environments can destroy a drill string, casing string and/or wellhead in a matter of hours. It is important to understand the nature of corrosion to know how it can be best controlled while using RMD/MPD/UBD technologies.

In addition to the erosion possibilities with conventional drilling, MPD/UBD routinely involves restricting the flow of returning fluids and drilled solids to surface through chokes and process piping. In MPD/UBD the expansion of gas or formation fluids/gases, together with the liquid drilling fluid and drilled solids, creates high effective velocities, additional hazards due to erosion and the possibility of gas hydrates formation due to temperature or pressure changes.

Internal erosion in surface equipment may be caused by the combination of solids, liquids or gases in the returning fluids along with the nature of the pressure drop stages returning fluids exhibit. If solids control equipment is inadequate in removing drilled

solids from fluids returned for recirculation, entrained solids in the injection stream may erode component internals.

See Appendix E: Erosion and Corrosion for general information about corrosion and how it impacts drilling equipment and operations.

It is important to address the following during planning:

- Discuss specifications for surface process equipment and piping with the drilling and separation/compression contractor(s) and agree upon a final design.
- Integrate items from this interchange, together with those from the drilling contractor and any other third-party concerns, into the P&ID and PFD. The PFD and P&ID should depict the intended surface equipment rig-up.
- Integrate all erosion concerns regarding line size into the design (e.g., straight lines wherever possible, maximum pressure rating, connection type, permissible flow rates, solids loading, etc.).
- Address erosion and corrosion concerns in the well design (refer to API RP 92M/92U for more information).

Consider the following about corrosion:

- The corrosion rate increases as fluid velocity increases. In MPD/UBD systems, increased velocity of fluids containing drilled solids will aid in surface cleaning (i.e., a scouring effect) which accelerates corrosion.
- Corrosion within a re-entry well should be evaluated prior to starting a RMD/MPD/UBD program. Any resulting relevant information should be included in the well program.
- The existence of oxygen, carbon dioxide and/or hydrogen sulphide in a fluid (especially water) can dramatically increase the corrosiveness of the fluid. Oxygen can be a component in MPD/UBD operations when dealing with injected gases. Corrosion of the BHA or drill string components is a major concern when using drilling fluids that are water based and, in particular, containing salts. This risk is compounded by any presence of oxygen in the circulation system (e.g., oxygen content within membrane-generated nitrogen).
- Corrosion could result in pitting, embrittlement, sulphide stress cracking or black sulphide coating which may lead to casing/drill string or surface equipment failure. Refer to IRP 01: Critical Sour Drilling and IRP 06: Critical Sour Underbalanced Drilling for more information.
- Corrosion may affect the well, the downhole equipment or the surface equipment.
- Corrosion can be expensive to repair.
- Casing corrosion may take several years to induce a leak.
- A five percent concentration of potassium chloride in the drilling fluid, often used for shale control, causes more corrosion than most other drilling fluids.

- Foul smelling, red or black make up water for the drilling fluid can help start the corrosion process.
- Corrosion happens quickly. Mitigations need to be timely.

IRP Monitoring programs shall be in place for the following:

- Corrosion
- Oxygen
- Flow Rate
- H_2S (Refer to IRP 01: Critical Sour Drilling and IRP 06: Critical Sour Underbalanced Drilling for more information)

Refer to the Monitoring section of Appendix E: Erosion and Corrosion for details about monitoring.

IRP Continuous readout monitors for oxygen injection using membrane nitrogen should be in place and calibration reports for the monitors should be available on-site.

IRP Immediate action should be taken to minimize the corrosive potential of the circulating media and produced fluids when corrosive conditions are detected.

Corrosive potential can be minimized in the following ways:

- Minimize or eliminate oxygen, carbon dioxide, hydrogen sulphide and chlorides in the injection stream.
- Add scavengers and/or inhibitors into the injection stream.
- Use corrosive resistant materials.
- Always use clean make up water.

The best protection against corrosion is to keep the pH of the drilling fluid above 9.0 (as measured in the returns).

IRP Effective corrosion management procedures shall be established prior to initiating RMD/MPD/UBD operations.

IRP The erosion management should include the following:

- Identification of components susceptible to erosion.
- A spare inventory list for components susceptible to erosion.
- An operational plan to replace eroded components.
- Erosion monitoring procedures if applicable (e.g., an Ultrasonic Thickness (UT) monitoring program for high corrosion/erosion situations).

- Increased drill pipe inspection frequency. Drill pipe external wear may be accelerated in MPD/UBD operations, especially in horizontal applications.

  Note: Drill pipe failure in MPD/UBD operations has higher level HSE consequences than in conventional operations (e.g., hydrocarbon/high pressure gas release at surface, pipe-light, etc.).

Solids in the return fluid stream can result in erosion of surface flow equipment. Erosion rate depends on the concentration, type and size of the solids and their transport velocity.

Safe operation for an RMD/MPD/UBD system requires the assessment, monitoring and management of erosion to prevent a loss of containment. Non-destructive testing may be insufficient for erosion monitoring if not completed on a regular basis.

IRP MPD/UBD service and equipment providers should adopt erosion control models to predict the erosion rate of MPD/UBD equipment under the planned flow conditions. The following should be included:

- Assessment of erosion risks to ensure the design is capable of tolerating the expected quantity of solids under the expected flowing conditions and duration of operations.
- Implementation of suitable erosion monitoring system and processes to ensure the wear does not exceed manufacturing specifications.
- Feedback of operating experience to develop optimum erosion designs.
- Monitoring with corrosion rings in the drill pipe should be included in the general program.

IRP All MPD/UBD surface and sensitive downhole equipment exposed to high pressures and/or high flow velocities should be inspected on a regular basis using industry accepted practices to monitor for materials erosion. Back-up or replacement parts should be on site during MPD/UBD operations.

Refer to the surface circulation system recommendations in IRP 06: Critical Sour Underbalanced Drilling for more detail.

Circulating fluids used in MPD/UBD wells and in-flowed reservoir fluids from MPD/UBD sections may involve chemicals corrosive to common drill string steels.

IRP Any anticorrosive or other chemical additives or treatments should be tested for possible negative interactions (e.g., foaming, etc.) with the drilling fluid.

See API RP 92U for more information about chemical interactions.

IRP Flow velocities in the primary flowline should be maintained below 55 m/second in absence of detailed erosion modelling.

Refer to API RP 14E for calculation methods to estimate erosional velocities of multiphase fluids containing drilled solids.

22.6 Well Control

For purposes of IRP 22, an influx that is within the operating limits of the Operations Matrix is not considered a well control event. If the operating limits of the Operations Matrix are exceeded (i.e., operations enter the red zone and require shut-in of the BOP), it is a well control event and conventional well control methods need to be utilized. See 22.8.5 Operations Matrix.

IRP Well control equipment and well control practices must be in accordance with local jurisdictional regulations (e.g., AER Directive 036: Drilling Blowout Prevention Requirements and Procedures).

IRP The rig's well control equipment shall be independent of the RMD/MPD/UBD system other than for the purpose of equalizing. The only exception is consideration for rig choke tie-in to secondary RMD/MPD/UBD surface separation equipment (see 22.6.5 Rig Choke System).

Conventional well control equipment includes a rig pump, hydraulic control remote (HCR) valve, choke manifold, degasser and flare tank/stack.

IRP All RMD/MPD/UBD operations should be bridged to conventional well control practices and be clearly communicated to ensure the safety of all personnel involved (i.e., procedures, on-site training, etc.), and mitigate risks associated with the complexities of RMD/MPD/UBD.

IRP Bridging documents should include influx management considerations for MPD operations, including influx detection and circulation.

Define all potential MPD/UBD events during planning and incorporate them into the MPD/UBD drilling program. Procedures that support MPD/UBD events and allow conventional well control practices are essential to successful and safe operations.

22.6.1 Barriers

In conventional drilling practices/RMD, an effective drilling fluid barrier is one that can be monitored and exerts an overbalanced hydrostatic pressure that exceeds non-cased hole formation pressures with a trip margin. The drilling fluid, along with other elements common to the secondary well barrier, make up the primary well barrier envelope (WBE).

In MPD operations (whether or not a hydrostatically underbalanced mud weight is used) and UBD operations (where, by definition, hydrostatically underbalanced mud weight is

used), the drilling fluid hydrostatic pressure alone is not sufficient to prevent formation fluids from entering the wellbore and flowing to surface. Therefore, additional barrier elements are introduced to complement the drilling fluid and act as a single system for the primary WBE. These additional primary barrier elements for MPD and UBD applications include, but are not limited to, the following:

- RCD
- MPD/UBD choke valve or MPD/UBD choke manifold
- MPD/UBD piping and flow lines
- Drill string
- NRVs

Consider creating a well barrier schematic to identify the WBE for each phase of the operation. Examples of such schematics can be found on Section 8 Well Control and Well Integrity, of the API RP 92M document and Section 13, Underbalanced and Managed Pressure Drilling and Completions Operations, of the NORSOK D-010 document (see Appendix K: References and Resources).

Table 3. Well Barrier Reference Table

Conventional Drilling/RMD	MPD/UBD
Primary Well Barriers	**Primary Well Barriers**
• Drilling Fluid • Casing* • Casing cement* • Wellhead*	A combination of the following: • RCD • MPD Choke Manifold • Flow Lines • NRV • Drill String • Drilling Fluid (hydrostatically over or underbalanced) • Casing* • Casing Cement* • Wellhead*
Secondary Well Barriers	**Secondary Well Barriers**
• Blowout Prevention Stack (BOPs) • Casing* • Casing cement* • Wellhead*	• Blowout Prevention Stack (BOPs) • Casing* • Casing cement* • Wellhead*

* Barrier element is common to both the primary and secondary WBE.

Note: BOPs need to be installed and function tested, but not necessarily activated, to be considered a barrier.

Note: Barriers can be temporary or permanent depending on the stage in the well life cycle.

IRP A minimum of two independent and tested well barriers (i.e., dual barriers) shall be in place for all RMD/MPD/UBD operations.

Note: Replacing the RCD bearing assembly with pressure on surface may require the use of the BOP as part of the primary barrier. This contingency procedure is the only scenario where an element of the secondary barrier can be used as part of the primary barrier.

IRP The execution of this procedure shall be temporary in nature.

IRP The BOP is part of the secondary barrier envelope and should not be used for planned events in MPD operations, such as drilling ahead or stripping drill string. A risk assessment should be performed for remedial operations that require the use of a secondary barrier.

IRP Hydrostatically underbalanced drilling fluids alone shall not be considered an effective barrier in RMD/MPD/UBD operations.

22.6.1.1 Well Barrier Objectives

IRP Both primary and secondary well barrier envelope functions and equipment shall be clearly defined in the drilling program for all MPD operations. The barriers shall be established for all stages of the well's life cycle (i.e., drilling and tripping the drilling BHA, running a completion, etc.), including when there are changes to the barrier envelope.

In conventional drilling (drilling in overbalanced condition)/RMD, the primary objective is to control the well by means of the hydrostatic pressure exerted by the drilling fluid.

In wells drilled with managed pressure drilling techniques, the primary objective is to maintain the wellbore pressure at or above the formation pressure. The primary well barrier is jointly maintained by the drilling fluid, surface pressure control equipment and additional elements as listed in Table 3 above.

When wells are drilled underbalanced, the primary objective is to maintain the wellbore pressure within the operating pressure envelope while safely processing the formation influx in the return flow line. The wellbore pressure is intentionally kept below the formation pressure for the well to be flowed in a controlled manner. The primary well barrier is jointly maintained by the drilling fluid, surface pressure control equipment and additional elements as listed in Table 3 above.

IRP A plan for reinstatement of a lost barrier element should be in place if a risk assessment indicates it is required.

IRP For MPD and UBD, the secondary well barrier's function and utilization shall be the same as in conventional drilling.

IRP If the primary WBE fails, the operator shall ensure that no activities, other than those intended to restore or replace the primary WBE, take place on the well.

22.6.1.2 Well Barrier Design, Selection, Construction and Acceptance Criteria

IRP An assessment of the risk associated with the intended operation shall be made prior to initiating any operation.

IRP The well control and kill procedure shall be established prior to the start to MPD/UBD operations.

IRP The primary and secondary WBE shall be able to withstand the maximum anticipated pressure expected for the planned operations plus an additional safety factor.

IRP Upon initial rig in, well barrier elements integrity should be verified prior to commencing the RMD/MPD/UBD operation.

22.6.2 Determination of Safe Operating Limits For Influx Management for MPD Operations

This section provides guidance and parameters used to determine the maximum influx volume that can be safely managed using the MPD equipment when creating the MPD Operations Matrix.

22.6.2.1 Surface Equipment Pressure Limits

IRP Equipment limitations for all components should be reviewed, including pressure relief valve settings.

IRP The maximum pressure of the surface equipment must not exceed the lowest pressure-rated component (weakest) of the MPD system.

IRP If managing influx using MPD equipment, the pressure at which the equipment was pressure tested shall be considered the operating limit for surface equipment.

IRP The RCD Sealing Element running life (or wear) should be considered when circulating influxes with the MPD equipment because the integrity of the element may decrease with use.

22.6.2.2 Downhole Pressure Limits

IRP The maximum pressure considering all pressure components – hydrostatic plus surface backpressure – in the open hole section while circulating an influx during MPD operations must not exceed the fracture gradient at any given depth.

22.6.2.3 Determination of Maximum Pressure During Influx Management Operations

IRP During influx management operations, the maximum pressure that can be held on surface should be determined by factoring in the equipment pressure limitations, downhole pressure limits, and a safety factor.

22.6.2.4 Surface Flow Rate Limits

IRP The MPD mud gas separator, piping, and other surface equipment limitations should be considered when determining the liquid and gas flow rates used to circulate influx out using MPD equipment.

IRP The maximum gas and liquid flow rates used during influx management operations shall not exceed the MPD mud gas separator, piping, and other surface equipment limitations.

22.6.2.5 MPD Influx Volume Limit

IRP Calculations must be made to determine the maximum influx volume that will result in the pressure profile exceeding either surface equipment or downhole pressure limitations.

IRP The static scenario should be considered when determining the operational influx volume limit, as this constitutes the worst-case scenario (pump failure during influx circulation operations). See API 92M for influx calculation methodologies.

IRP The MPD influx volume limit should be considered when setting the volume operating limit on the Influx Indicator axis on the MPD operations matrix. If the MPD influx volume limit is exceeded, the secondary well control system should be used. The operating limit should be lower than the MPD influx volume limit.

22.6.3 Influx Detection, Control and Circulation Using MPD Equipment

22.6.3.1 Influx Detection

Effective influx control and circulation using MPD (Managed Pressure Drilling) equipment requires reliable detection of influx volumes to ensure that operational limits are not exceeded.

IRP The MPD system shall be able to reliably measure influx volumes if influxes are planned to be circulated out using the MPD equipment.

Accurately determining influx volume can be challenging due to various factors. These may be considered both during measurement and when developing the MPD Operations Matrix to incorporate appropriate safety margins. Such factors may include:

- Gas solubility in oil-based muds (OBM),
- Size of surface mud tanks
- Fluid compressibility
- Thermal effects
- Surface flow meter measurement resolution

22.6.3.2 Influx Arrest While Drilling

If an influx occurs within the planned limit set in the Operations Matrix, it can be controlled with MPD equipment.

Controlling an influx with the MPD equipment refers to activities to restore the overbalanced condition to prevent further influxes from entering the wellbore. This can be achieved by several means, but it requires increasing the bottomhole pressure and continuously verifying influx volumes to prevent additional influxes from entering the wellbore.

Bottomhole pressure increase is usually achieved by increasing the surface backpressure with the MPD system until pressure and flow-related parameters indicate the influx has been stopped. The following parameters can be used as indicators that an influx has been stopped:

- Active pit measurement (e.g., pit gain): A stabilization in initial pit gain indicates an influx has been stopped. The pit gain remains constant as no more influxes enter the wellbore.
- Delta Flow: Once the flow-in measurement equals the flow-out measurement (delta flow reading equals zero).
- Standpipe Pressure: During the initial stages of influx control, once the influx has been controlled, the standpipe pressure should remain constant if the flow rate remains steady.

IRP An influx should only be considered controlled when the pit gain no longer increases above the initial pit gain, the delta flow reading equals zero, and the standpipe pressure remains constant.

IRP All influx control operations shall adhere to pressure ranges defined in the MPD Operations Matrix.

22.6.3.3 Influx Circulation

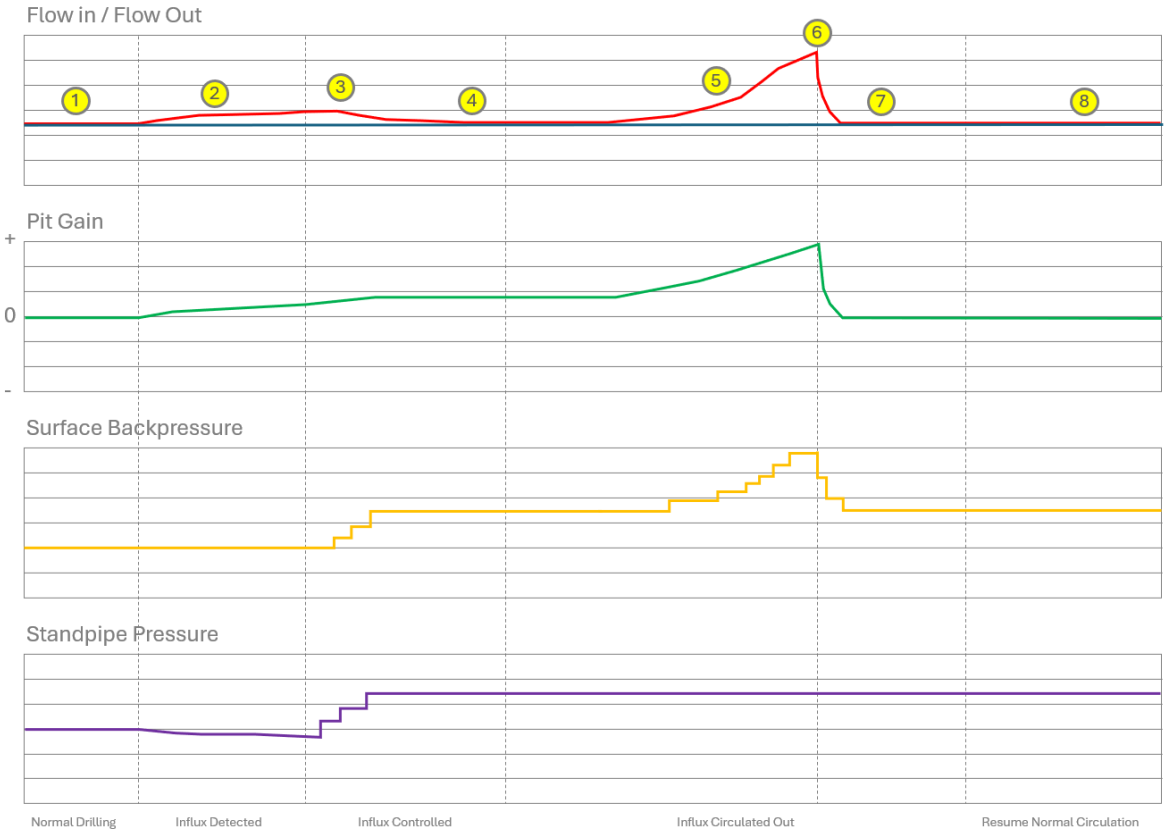
Once the influx has been confirmed as controlled, and the operational parameters fall within the MPD Operations Matrix limits for influx circulation with the MPD equipment, the influx can be circulated out using pre-defined procedures.

IRP A pre-defined influx circulation procedure must be developed and agreed upon between the operator, drilling contractor and/or MPD service provider during the planning phase of the MPD operation if influxes within the MPD Operations Matrix limits will be circulated out using the MPD equipment. The procedure must contain provisions to switch to secondary well control procedures in case of any contingencies.

IRP Before circulating an influx using the MPD equipment, the influx must be deemed controlled in accordance with section 22.6.3.2.

IRP All surface equipment limits should be reviewed, and circulation parameters should be verified in advance if the influx will be circulated using MPD equipment. These parameters should be monitored continuously during the influx circulation operation. Figure 1 provides influx management plots illustrating the process of influx detection, arrest, and circulation.

Figure 1. Influx Management Plots



1. Normal drilling conditions: Flow in = Flow out, no Pit Gain.
2. Influx enters the wellbore: Flow In > Flow Out, Pit Gain is positive. Slight decrease in SPP due to loss of hydrostatic pressure and gas in the system.
3. SBP is increased in steps to increase BHP to control the influx.
4. Influx is controlled: Flow in = Flow Out and Pit Gain remains constant.
5. Influx Circulation. SBP is adjusted to keep the SPP constant. Gas starts expanding in the wellbore, causing Flow Out and Pit Gain to increase.
6. Highest SBP applied. Influx has expanded to its maximum length.
7. Influx leaves the well. Pit gain value is zero, Flow In = Flow Out. SBP is higher than in step 1 (a higher SBP value is necessary to control the well based on the updated formation pressure).
8. New normal drilling conditions: Flow in = Flow out, no Pit Gain.

22.6.4 BOP Configurations

IRP BOP configuration for all wells must be as per local jurisdictional regulations. A more robust BOP stack may be required for sour operations.

Refer to IRP 01: Critical Sour Drilling and IRP 06: Critical Sour Underbalanced Drilling for more information on sour operations.

IRP A method to access and energize/bleed pressure from below the annular preventer (and above the pipe rams/blind rams) should be included in any stack with an RCD to prevent trapped pressures.

IRP As in conventional well control, the BOP stack shall always remain in the control of the driller.

Integrity of the drill string and connections, including the non-return valve (NRV), is critical for operations where live tripping is required.

IRP The integrity of the drill string and connections shall be verified prior to tripping operations (see 22.12.4 NRVs).

Refer to the Risk Register for integrity testing options and 22.7.1 Optional RMD/MPD/UBD Equipment for options to increase lubricating space.

Ensure all BHA and BOP components are accurately measured and recorded. The following two measurements are critical:

1. The blind ram to the base of the RCD.
2. The top of the annular preventer to the base of the RCD element.

Well control events are most likely to occur when the drill string is in the well. A Downhole Isolation Valve can help minimize the risk of a well control event when complex assemblies are required but there is a trade-off in the increased risk of straying from conventional practices. Usually, downhole isolation valves rely on differential pressure to seal and this may be considered during the risk assessment and planning phase. Conventional ram configurations can hinder well control efforts such as servicing a failed HCR system or washing an HCR outlet spool.

When servicing a failed annular preventer, double isolation is possible with a drill string hang-off on the lowermost pipe rams and by closing the blind ram.

Note: A drill string hang-off is not a simple operation. Implications and risks need to be understood and risk assessed before undertaking this operation.

When the secondary flowline outlet spool is washed-out or eroded, isolation is possible (i.e., closing of the pipe rams) when pipe rams are below the blind rams and a secondary flowline outlet spool is above the pipe rams.

22.6.5 Rig Choke System

IRP The rig and RMD/MPD/UBD equipment must have separate inlets to the flare stack.

IRP Any RMD/MPD/UBD surface separation equipment tied into the rig's manifold shall not prevent the use of the rig's primary well control separation equipment.

IRP Any RMD/MPD/UBD surface separation equipment connected to the rig's manifold shall have an isolation valve that has the same or higher pressure rating as the rig's manifold. See drawing

IRP RMD/MPD/UBD surface separation equipment shall not be used as the primary degasser during well control. It may be used as a secondary degasser.

IRP A risk assessment shall be completed if RMD/MPD/UBD surface separation equipment is to be utilized as secondary well control equipment.

Consider the following:

- Maximums for flow rate and separation capacity of separation equipment
- Plugging of equipment from being drilled through may compromise well control ability
- H_2S/CO_2 compatibility and/or rating of the separation equipment
- Integrity of equipment may be compromised by drilling operations (e.g., erosion)
- Incorporation of secondary separation equipment inlets
- Identification of well control path and procedures
- Flushing
- Isolation of valves and lines during standby or long periods of non-operation

22.6.6 Tubing Spool

A tubing spool is optional and based on operational need (see 22.7.1 Optional RMD/MPD/UBD Equipment). It can assist in running and/or snubbing complex completion assemblies. Isolation using a tubing hanger assembly can allow for installation of the snubbing unit. Refer to IRP 15: Snubbing Operations for more information.

A tubing spool simplifies UBD completion procedures by providing a means of isolating the well to remove drilling BOPs and install a wellhead.

In the event the pipe rams are closed, a kill line could be installed to the tubing spool to allow for bullhead killing.

22.6.7 Rotating Control Device and Primary Flowline Outlet

The RCD requires frequent inspection, intervention (particularly during tripping operations) and servicing. The BOP annular preventer and rams can be used to isolate the RCD and primary flowline outlet spool.

IRP The RCD and the primary flowline outlet shall be positioned above the BOP stack.

For MPD/UBD, an isolation valve on the primary MPD flowline is required for isolation of the RCD from the MPD/UBD choke manifold.

IRP An isolation valve shall not be used in place of a choke to control pressure or flow.

Positioning valves in the primary flowline adjacent to the RCD poses significant hazards to personnel during rig-up/down.

The likelihood of erosion washout between the RCD and upstream of the MPD/UBD choke manifold is very low. Any erosion washout of the MPD/UBD primary flowline may require the well to be shut in and/or flow diverted with the MPD/UBD equipment isolated. In this scenario an independent pressure bleed-off of the RCD will be necessary in order to manage potentially trapped pressure.

See 22.12.3 Rotating Control Devices for more information.

22.6.8 Casing Pressure Monitoring

IRP The casing and/or annulus pressure shall be monitored at all times during MPD/UBD operations.

IRP For MPD/UBD operations the casing pressure sensor should be installed on the secondary flowline or an outlet on the tubing spool (i.e., below blind ram). This allows pressure to be monitored when the blind rams are closed.

IRP BOP valve configurations shall accommodate exposing the casing pressure monitoring gauge/sensor to casing pressure during all MPD/UBD operations.

22.6.9 Standpipe Manifold

Trapped pressure energized by a gas phase poses a significant hazard to rig floor personnel during drill string connections.

IRP **Procedures and equipment to prevent trapped pressure hazards shall be in place during drill string connection.**

IRP Independent high and/or low pressure bleed-offs should be rigged in and available during MPD/UBD two phase operations.

Note: The low pressure bleed-off should be capable of relieving up to atmospheric pressure. The high pressure bleed-off should be routed to the separation system.

IRP **A check valve shall be installed upstream of the gas/liquid tie-in to prevent reverse flow from the gas injection line to the standpipe line for MPD/UBD two phase operations (see 22.7 Process Flow Diagrams).**

22.6.10Maintaining MPD/UBD Separator Pressure

Site-specific operations may pose risk to the MPD/UBD separator system.

IRP Site-specific risk and hazard assessment should be conducted to assess whether the MPD/UBD separator can retain its operating pressure and identify contingency plans in case it does not.

Contingency plans may include the use of following:

- A gas source for MPD/UBD separator pressure maintenance
- A flame arrestor or detonator
- A backpressure valve

22.6.11 Pressurized Sample Catchers

Pressurized sample catchers can pose hazards to personnel. They can become over-pressured with blocked flow if sample catchers are not pressure rated equivalent to the choke manifold (i.e., a pressure specification break) or could have a release due to trapped pressures within the system.

Note: Blocked flow risk is significantly higher when incompressible circulation systems are used because the response time to over-pressure is significantly lower.

IRP Samples should be captured by conventional practice at the shale shaker, factoring in additional cuttings lag time with the separation system.

IRP A hazard assessment, with mitigations identified, shall be performed for the use of pressurized sample catchers.

Potential mitigations may include the following:

- Use a pressure relief system (i.e., protection against specification break)
- Avoid diverting all flow through the pressurized sample catcher system.

Design the sample catcher system to have the same pressure rating as the MPD/UBD choke manifold.

22.7 Process Flow Diagrams

There are several system configurations possible for applying RMD/MPD/UBD technology so standardization of systems is challenging. There is broad variability of well parameters and versatility in the technology that introduce numerous potential risks. Within IRP 22 the following PFD systems have been identified to help control risks and achieve industry standardization for the majority of onshore applications anticipated within the Western Canadian Sedimentary Basin:

- RMD System
- Sweet MPD System
- Sour MPD System
- Sweet UBD System
- Sour UBD System

All of the PFDs are shown in Appendix F: Process Flow Diagrams and are available with IRP 22 on the Energy Safety Canada website.

IRP The PFD and P&ID shall be discussed at the pre-job safety meeting and readily available, at minimum, in the doghouse and the command centre (if present).

The PFD provides a method to document the actual flow situation available on the rig floor. The driller's reference PFD can be kept current using erasable markers to denote open (O) and closed (X) valves in the process stream (see 22.13 Surface Circulating System).

22.7.1 Optional RMD/MPD/UBD Equipment

The IRP 22 PFDs are example configurations of the minimum equipment required for the intended operation. There are several optional pieces of equipment that can be added for site or operation specific requirements. There are also optional configurations for some components. The optional equipment and configurations are not shown on the PFDs but are listed in Table 4.

Table 4. Optional PFD Equipment and Configurations

Equipment/Configuration	PFD	Notes
Auxiliary Pump	MPD Sour MPD Sweet	• Provides the ability to compensate for additional required SBP to maintain a constant bottomhole pressure (i.e., when there is a leak in the closed system from chokes or losses to formation). • Can be used during static conditions for well monitoring and well control detection.
Backpressure Valve (BPV)	MPD Sweet MPD Sour UBD Sweet UBD Sour	• Required for pressurized MPD/UBD separators.
Backup Pressure Measurement Device	MPD Sweet MPD Sour UBD Sweet UBD Sour	
BOP Stack Configuration	All	• The PFDs show a sample configuration for information purposes only. • Local jurisdictional regulations must be consulted for optional and mandatory equipment (e.g., AER Directive 36: Drilling Blowout Prevention Requirements and Procedures). • Configuration may change depending on expected pressures or sweet vs. sour operations.
Chemical Injection System	RMD MPD Sweet MPD Sour UBD Sweet UBD Sour	• Allows chemicals to be injected downhole rather than in the drilling fluid tanks (e.g., foam surfactants, corrosion inhibitors oxygen, scavengers, etc.). • Allows chemicals to be injected into the return lines (e.g., de-foam).
Drilling Fluid Gas Source	MPD Sweet MPD Sour UBD Sweet UBD Sour	• Provides the ability to inject a gas system to achieve a multiphase drilling fluid system (depending on the well's objective). • For UBD, equipment may not be required for flowing drilling applications.
Excess Storage	MPD Sweet UBD Sweet	• Drilling fluid storage tanks (i.e., tank farm). • Upright tanks Commonly utilized.
Flow/Mass Balance Meter	RMD MPD Sweet MPD Sour	• Provides measurement of injected and/or produced fluid flow or mass rates from the well. • Assists in well control detection. • May be required for automated MPD choke control.
H_2S Scrubber	MPD Sour UBD Sour	• May be required on sour or critical sour locations to sweeten fluids.

Equipment/Configuration	PFD	Notes
HCR Configuration	MPD Sweet MPD Sour UBD Sweet UBD Sour	• HCR should not be utilized as part of normal MPD/UBD operations and should be independent of MPD/UBD equipment • See Figure 2 below for a visual representation of the typical and Figures 3, 4 and 5 for optional configurations. • Positioning may be outside an additional hydraulic stop valve off the BOP stack and downstream of the equalization tie-in point (Figure 5) • HCR positioning requirements may depend on BOP Stack (and well class). Refer to AER Directive 36: Drilling Blowout Prevention Requirements and Procedures for more information.
Liquid and/or Slurry Transfer Pump	RMD MPD Sweet UBD Sweet	• Required to assist in fluid and/or slurry transfer when gravity/RMD/ MPD/UBD separator pressure is not sufficient.
Low Pressure/Stage MPD/UBD Separator	MPD Sour UBD Sour	• Used during closed loop drilling operations. • Increase fluid retention time for more effective separation. • Further breakdown of gasified fluid to separate gas.
Mist Pump (Low Volume Pump)	MPD Sweet MPD Sour UBD Sweet UBD Sour	• Provides the ability to pump at rates lower than the rig pump capacity.
Positive Pressure/Instrumentation Gas source	MPD Sweet MPD Sour UBD Sweet UBD Sour	• Provides the ability to maintain positive pressure in a pressurized MPD/UBD separator for shipping purposes. • May be required to fuel some instrumentation.
Pressure Relief Valve (PRV)	MPD Sweet MPD Sour UBD Sweet UBD Sour	• Required for pressurized MPD/UBD separators. • Optional upstream of the choke valve.
Returns Gas Flow Meter (Gas Detector)	RMD	• Provides a means to verify whether the amount of gas in the returns fluids is within the operational limits defined in the RMD operations matrix.
Rig Choke Tie-In to MPD/UBD Surface Separation Equipment	MPD Sweet MPD Sour UBD Sweet UBD Sour	• See Figure 6 below. • Refer to 22.6.5 Rig Choke System.
Sample Catcher	MPD Sweet MPD Sour UBD Sweet UBD Sour	• Allows for accurate formation sampling prior to MPD/UBD separator.

Equipment/Configuration	PFD	Notes
Secondary Flowline	MPD Sweet MPD Sour UBD Sweet UBD Sour	• Depending on the rig-up of the primary flowline, a secondary flowline may be required. • If there is a secondary flowline there should be a set of rams below the outlet on the BOP stack for well control for drilling operations. • Must conform to local jurisdictional regulations for well control. • Should come off the BOP stack (approved location based on regulation) and tie into MPD/UBD choke manifold. • Secondary flowline needs to be at least 88.9 mm (3.5 in.).
Separator with BPV	UBD Sweet	• An atmospheric separator may replace a UBD separator with BPV for flow drilling operations if properly risk assessed.
Spacer Spool(s) in the BOP Configuration	All	• Provides increased lubrication length.
Staged (Dual Drop) Choke System	MPD Sweet MPD Sour UBD Sweet UBD Sour	• In some operations (e.g., high erosion or hydrates) a dual drop choke manifold may be utilized. • Allows a staged pressure drop (e.g., 10k to 5k to 3k) • Reduces the effects of erosion and hydrate formation due to reduced temperature change or velocity
Tubing Spool	All	• Local jurisdictional regulations must be consulted for optional and mandatory equipment on the BOP stack (e.g., AER Directive 36: Drilling Blowout Prevention Requirements and Procedures).

The figures below show the typical HCR valve configuration (Figure 2) and three optional configurations (Figures 3, 4 and 5). Consult local jurisdictional regulations for HCR configuration requirements.

Figure 2. Typical HCR Valve Configuration

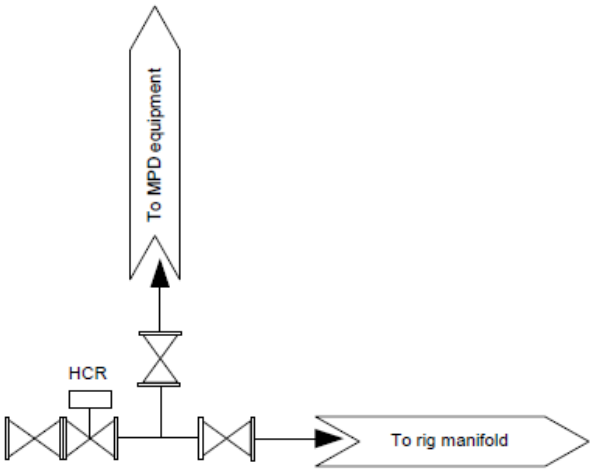


Figure 3. HCR Optional Configuration 1

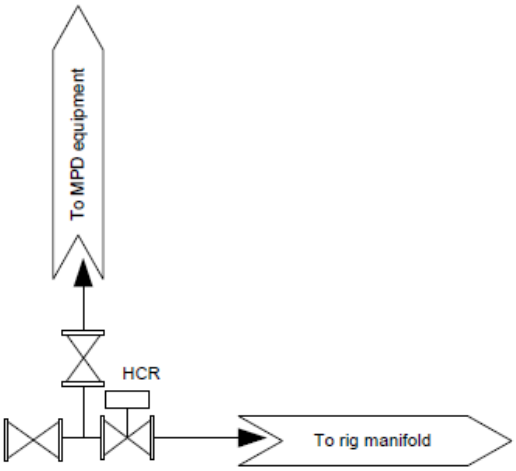


Figure 4. HCR Optional Configuration 2

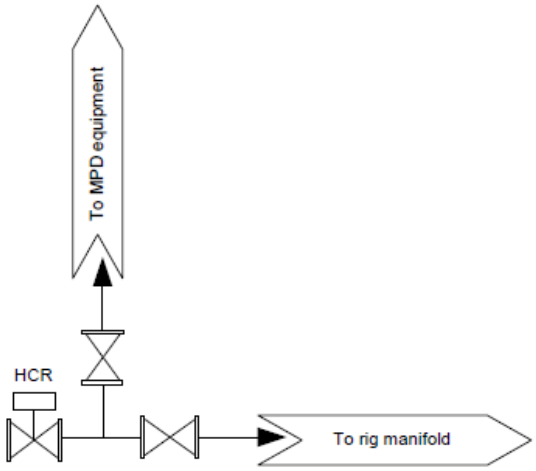


Figure 5. HCR Optional Configuration 3

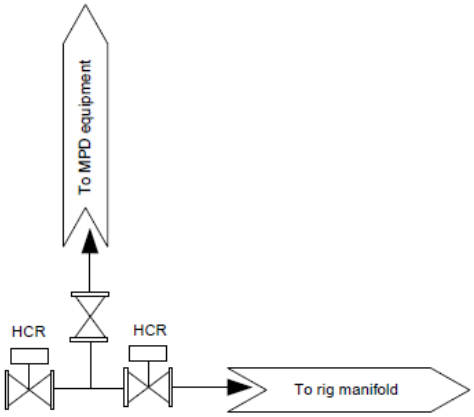
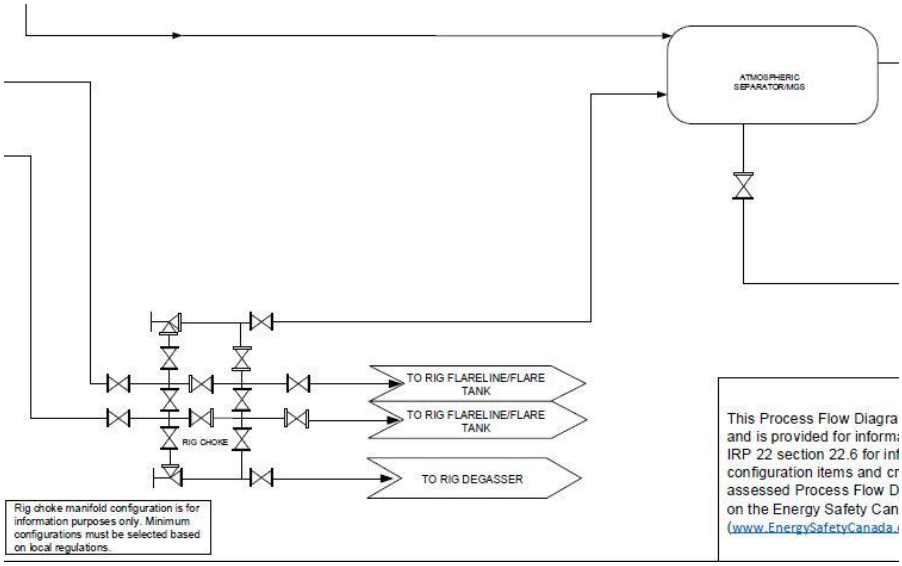


Figure 6. Rig Choke Tie-In to Surface Separation Equipment



Note: This diagram is a subsection of the larger process flow diagram shown as Figure 18 in Appendix F.

22.7.2 RMD System

The RMD PFD setup is recommended when using drilling fluid weight less than pore pressure but the well does not demonstrate the capability to flow (e.g., unconventional shale formations that generally don't flow unless stimulated).

IRP The flow shall be directed from the RCD to a dedicated degasser before flowing to the shakers.

See Figure 13 in Appendix F: Process Flow Diagrams

22.7.3 Sweet MPD System

See Figure 14 in Appendix F: Process Flow Diagrams.

22.7.4 Sour MPD System

IRP A blind/shear ram should be included in a sour MPD system.

Consider using a closed circulating system when local jurisdictional regulations for H_2S concentration are exceeded (see Glossary for the definition of a closed circulating system).

IRP A multi-stage separation system should be used for site-specific scenarios that require recirculation of drilling fluids.

IRP Sour fluids shall not be recirculated down the drill string. An H_2S scrubbing system shall be used.

See Figure 115 in Appendix F: Process Flow Diagrams

22.7.5 Sweet UBD System

A second pipe ram can be considered in a sweet UBD system to handle erosional washout. A possible substitute for the second pipe ram is a blind/shear ram.

Note: If a blind/shear ram is used there are increased risks to be evaluated (e.g., shearing will cause the upper section of the drill string or pipe to be ejected more violently than usual with substantial expansion likely, potential for raining debris, etc.). Evacuation procedures need to consider these risks.

Any substitute for the second pipe ram would be subject to a site-specific risk assessment.

See Figure 16 in Appendix F: Process Flow Diagrams.

22.7.6 Sour UBD System

IRP A blind/shear ram should be included in a sour UBD system to handle erosional washout.

Note: If a blind/shear ram is used there are increased risks to be evaluated (e.g., shearing will cause the upper section of the drill string or pipe to be ejected more violently than usual with substantial expansion likely, potential for raining debris, etc.). Evacuation procedures need to consider these risks.

IRP A closed circulating system shall be used when local jurisdictional regulations for H_2S concentration are exceeded (see Appendix K: Glossary for the definition of a closed circulating system).

IRP A multi-stage separation system should be used for site-specific scenarios that require recirculation of drilling fluids.

IRP Sour fluids shall not be recirculated down the drill string. An H_2S scrubbing system shall be used.

See Figure 17 in Appendix F: Process Flow Diagrams.

22.8 Engineering Requirements for High Risk Scenarios

Both UBD and MPD rely on more precise information than conventional drilling (e.g., reservoir type, location, contents, pressures, temperatures, stability, etc.). MPD/UBD operations are complex. Successful delivery is contingent on the personnel, equipment, processes and procedures all operating within expected limits.

Errors, omissions or failure to plan adequately for specific situations can impact operational hazards and equipment requirements which can negatively impact project execution time.

22.8.1 Simulations

Single and/or multiphase flow modelling is commonly used in all aspects of planning and implementing MPD/UBD programs. Sophisticated flow models simulate well conditions to investigate factors ranging from MPD/UBD feasibility to optimizing changes in operating parameters caused by changing conditions during the MPD/UBD operations. It is a good practice to validate simulations against known outputs or previously drilled sections to demonstrate accuracy.

Simulation results can be used as follows:

- To establish operating parameters including injection rates along with wellhead and downhole pressures.
- To ensure adequate hole cleaning or motor performance.
- To evaluate fluids to achieve MPD or UBD conditions.
- To identify equipment technical specifications.
- To define the operating envelope for MPD/UBD.
- To monitor drilling to determine whether changes are needed to achieve operating parameters.
- To develop an understanding of reservoir performance.

22.8.2 Operations Envelope

The operating envelope establishes the range of conditions for which MPD/UBD operations can be safely achieved and provides guidance in making appropriate changes to maintain MPD/UBD conditions while satisfying other operational requirements.

IRP **A management of change shall be completed if onsite conditions do not closely match the planned MPD/UBD operational envelope. MPD/UBD operations shall not proceed until the risks and mitigations are identified and communicated to onsite personnel.**

22.8.3 Equipment Specifications

The equipment specifications necessary to execute a specific program include, but are not limited to, the following:

- RMD/MPD/UBD Separator sizing
- Volume requirements
- Drill string requirements
- Wellhead requirements
- RCD requirements
- Choke requirements
- Flowline sizing
- Flare stack height and sizing (see AER D060: Upstream Petroleum Industry Flaring, Incinerating, and Venting for more information)
- Liquid and gas injection rates
- Operational BOP equipment versus well control BOP equipment
- Specialized tripping equipment (e.g., snubbing, DIV)
- Surface tank fluid handling and management

IRP **Risks associated with the specific equipment rig-up and program shall be evaluated.**

IRP Procedures, equipment and personnel to mitigate hazards identified in the risk assessment should be in place before operations begin.

IRP All valves upstream of the choke and on the bypass should be full bore.

Consider reliability when choosing valves (e.g., API 6A PR2 valve vs. PR1).

22.8.4 Lease and Wellsite Spacing for Equipment

UBD, MPD and RMD operations involve more equipment than conventional drilling or completion activity. It is common for extensive conventional activity to take place prior to RMD/MPD/UBD operations. This can leave little space on site for the RMD/MPD/UBD equipment.

IRP RMD/MPD/UBD equipment requirements (space and positioning) should be considered during wellsite spacing planning.

IRP RMD/MPD/UBD service providers should provide a site-specific lease spacing diagram for their equipment and conduct site inspections to ensure accuracy.

IRP Lease and wellsite spacing must be in compliance with the spacing requirements of the local jurisdictional regulator.

Well design spacing considerations include the following:

- Lease survey accuracy
- Rig layout accuracy
- RMD/MPD/UBD service provider spacing requirements
- Local jurisdictional regulations for stack height and flaring

Refer to IRP 20: Wellsite Design Spacing Recommendations for detail about wellsite spacing considerations and jurisdictional regulations.

22.8.5 Operations Matrix

The primary WBE for conventional/RMD operations is provided by the drilling fluid and other elements common to the secondary well barrier (see Table 3 in 22.6.1 Barriers). In MPD/UBD, the drilling fluid works in conjunction other barrier elements (as per Table 3 in 22.6.1 Barriers) to produce a targeted dynamic drawdown (UBD) or planned bottomhole pressure (MPD).

In UBD operations, reservoir inflow combines with injected fluids at the formation face. Surface flow of energized fluids and bottomhole pressure is controlled by managing surface wellhead pressure. Controlling bottomhole pressure limits the reservoir drawdown (i.e., the pressure difference between existing reservoir pressure and the prevailing pressure in the wellbore) which controls the reservoir production rate.

IRP Manageable wellhead pressures and returning potential reservoir fluids (particularly the gas phase) shall be clearly defined in the RMD/MPD/UBD Operations Matrix.

Defined pressures and flow rates allow for sufficient reaction time for crews to adjust the system in the event manageable levels are temporarily exceeded. The maximum pressure and flow rate ratings of equipment are safety-factored to the manageable operating envelope and provide an appropriate range for allowing adjustments when nearing the system's operability maximums.

The RMD/MPD/UBD Operations Matrices define an equipment operating envelope for drilling operations and bridge the RMD/MPD/UBD operation to conventional well control. They provide an illustration of appropriate actions for the RMD/MPD/UBD personnel to return the well flow rate and wellhead pressure parameters to the manageable operating envelope.

Note: Surface pressure limits used in the operational matrix need to consider pipe rotation and pipe movement. These limitations vary by RCD model and seal element material.

IRP Operators and qualified RMD/MPD/UBD service providers shall develop and follow a site-specific risk-based operations matrix for each RMD/MPD/UBD operation and post it in the doghouse.

The operations matrices are intended to be project specific and require customization for each project based on project equipment design limitations and well parameters. The matrix is a living on-site document that has to be updated regularly by qualified personnel to reflect current drilling conditions.

22.8.5.1 RMD Operations Matrix

The RMD Operations Matrix defines the indicators for RMD and identifies actions to take. Figure 7 shows a baseline template RMD Operations Matrix.

Figure 7. Baseline Template RMD Operations Matrix

Status	Indicators
Continue drilling	• There is no continuous flare while off-bottom circulating. • There is no pit gain. • There is no flow observed during the flow check (static conditions).
Cease drilling Increase drilling fluid weight to increase bottomhole pressure or minimize gas	One or more of the following indicators would require action: • There is a noticeable increase in flare. • There is measurable gas flow change (if available). • There is a change in connection gas. • There is flow observed during static conditions.
Shut in on rig's BOP (conventional well control)	One or more of the following indicators would require that the well be shut-in with the Rig's BOPs: • Pit gains. • Conventional kick warning signs. • Inability to restore well indicators to the green area.

22.8.5.2 MPD Operations Matrix

Surface pressure indicators are based on the weakest link taking into consideration surface equipment pressure ratings, formation integrity and MACP.

IRP The limits defined in the matrix shall be based on the expected operating conditions rather than the upper limits of the system. It shall include static and dynamic pressure ratings and RPM limits.

All conditions listed in the Baseline Template MPD Operations Matrix and any added during customization require risk and hazard assessment (see 22.4 Hazard Identification and Risk Assessment).

IRP All managed pressure operations (e.g., FITs/LOTs, MPD cementing, stripping procedures, etc.) shall be accounted for in the MPD Operations Matrix.

Figure 8 shows a baseline template MPD Operations Matrix. This baseline is based on the information in API RP 92M.

Figure 8. Baseline Template MPD Operations Matrix

Operating Company Drilling Contractor / Rig ID Well Name Well Section Mud Weight		Surface Pressure Indicator			
		Range 1[1] (At Planned Drilling Back-pressure)	**Range 2[2] (At Planned Connection Back-pressure)**	**Range 3 (> Planned Back-pressure and < Back-pressure Limit[3])**	**Range 4 (≥ Back-pressure Limit)**
Influx Indicator	**No influx**	Continue drilling	Continue operation	Continue drilling Adjust drilling parameters to decrease WHP	Secure well Evaluate next planned action
	Range 1 (≤ Planned Limit[4])	Continue drilling Adjust drilling parameters to increase BHP	Continue operation Adjust parameters to increase BHP	Cease drilling Adjust drilling parameters to increase BHP	Secure well Evaluate next planned action
	Range 2 (>Planned and < Operating Limit)	Cease drilling Adjust drilling parameters to increase BHP	Cease operation Adjust parameters to increase BHP	Secure well and evaluate next planned action	Secure well Evaluate next planned action
	Range 3 (≥ Operating Limit[5])	Secure well and evaluate next planned action	Secure well and evaluate next planned action	Secure well and evaluate next planned action	Secure well Evaluate next planned action
Continue drilling		In the green area, influx and surface pressure are as expected and controllable. Drilling ahead is permitted. The following downhole conditions remain within the managed pressure objective: • Drilling fluids in use • Capability to control wellhead pressure (dynamically and statically) • Flow capacity of the entire circulation system (with reliable measurement)			
Continue drilling **Adjust drilling parameters to increase BHP**		If the operation is in the yellow area BHECD is too low. Take action to increase BHP and/or decrease WHP (e.g., by increasing drilling fluid weight). Discontinue drilling if there is continuous influx from the formation.			
Cease drilling **Adjust drilling parameters to increase BHP**		Planned limit has been exceeded during drilling. BHECD, including annular friction losses, is too low. Drilling must be stopped. At this point, all actions need to bring the well to a manageable condition (green area).			
Secure well **Evaluate next planned action**		If all measures taken to restore well parameters into the green area fail, secure well and evaluate next planned action. MPD operations can resume once the well is stabilized.			

[1] RCD Dynamic pressure readings.

[2] RCD Static pressure readings.

[3] Backpressure limit should be calculated. May be limited by casing design, surface equipment limitations, formation breakdown pressure, etc.

[4] Planned Limit is the limit below which drilling can continue.

[5] Operating Limit is the limit above which MPD ceases and a transition to well control operations is required.

22.8.5.3 UBD Operations Matrix

The Min and Max ranges used in the Baseline Template UBD Operations Matrix should be determined by the operator using a risk-based approach. Customization consider the variety of formation and circulation system pressures and flow limitations.

All conditions listed in the Baseline Template UBD Operations Matrix and any added during customization require risk and hazard assessment (see 22.4 Hazard Identification and Risk Assessment).

Figure 9 shows a baseline template UPD Operations Matrix. The Min and Max values are as defined in Tables 5 and 6. This baseline is based on the information in API RP 92U.

Table 5. Wellhead/Surface Flowing Pressure

Name	Description
Min1	Pressure required for reasonable operation and pressure/flow rate monitoring for the circulation system in use. Depends on surface lines pressure drop, minimum UBD separator working pressure, etc.
Max1	50% of the RCD's dynamic rating is often suggested as a starting point. This should be reviewed with the equipment provider based on the well parameters and should be consistent with other risk-based pressure limitations in the system. If wellhead pressures increase much above this value, there is the potential to exceed the RCD's dynamic rating (e.g. pipe rotation and reciprocation possible). This may require switching to the RCD static condition (i.e., no rotation / reciprocation). If high pressure UBD separators are used instead of choking systems, considerations must be made to consider the UBD separator working pressure limit when calculating Max1.
Max2	Should be below the RCD's lower STATIC limitation—80% is often suggested as a starting point. This should be reviewed with the equipment provider based on the well parameters. If the situation is allowed to progress to the point flowing wellhead pressure closely approaches the RCD's dynamic limit (or some other design-limit pressure factor), changing from dynamic to static will be imminent. More operational flexibility is possible if the operational change is made prior to it ceasing to be an option.

Table 6. Surface Flow Rate

Name	Description
Max1	50% of the system's rated gas/liquid flow capacity, all other limiting factors notwithstanding.
Max2	Should be below the system's flow capacity maximum, and 80% is often suggested as a starting point. This should be reviewed with the equipment provider based on the well parameters.

Figure 9. Baseline Template UBD Flow Control Matrix

		Wellhead/Surface Flowing Pressure		
		Range 1 (Min1-Max1)	**Range 2 (Max1-Max2)**	**Range 3 (> Max 2)**
Surface Flow Rates	**Range 1 (Min1 – Max1)**	Continue drilling	Continue drilling Adjust drilling rates to increase WHP	Secure well Evaluate next planned action
	Range 2 (Max1 – Max2)	Continue drilling Adjust drilling rates to increase BHP	Cease drilling Adjust drilling rates to increase BHP	Secure well Evaluate next planned action
	Range 3 (> Max2)	Secure well Evaluate next planned action	Secure well Evaluate next planned action	Secure well Evaluate next planned action

Continue drilling	In the green area, flow rate and wellhead pressure are as expected and controllable. Drilling ahead is permitted. The following downhole conditions remain within the underbalanced operational envelope: • Formation flow capacity • Formation stability limits • Appropriate drawdown • Drilling fluids in use • Capability to control wellhead pressure • Flow capacity of the entire circulation system (including reliable measurement) • Erosion potential • Maximization of element service life of the RCD • Casing/wellhead design limits
Continue drilling **Adjust drilling rates to increase BHP**	If either the wellhead/surface flowing pressure or the surface flow rates exceed the green area, measures need to be taken to bring those parameters back to Range 1. Drilling can continue while these measures are taken. Measures may include the following (depending on which parameters exceed Range 1): • Increase wellhead/surface flowing pressure • Increase injection liquid flow rate • Decrease service gas flow rate (in cases where service gas is injected) • Increase drilling fluid density
Cease drilling **Adjust drilling rates to increase BHP**	If the operation is in the orange area either the observed flow rate or wellhead pressure is too high. Injection rates, and possibly surface backpressure, should be adjusted until operations return to the green area. If these measures fail to achieve system stability cease drilling while adjustments are made then cease rotation (this phase requires the RCD in static mode) while continuing to adjust injection parameters.
Secure well **Evaluate next planned action**	If all measures taken to restore well parameters into the green area fail shut in the well with the rig's BOPs. Subsequent operations are dependent on the operator's assessment of whether the well can be drilled in UBD mode and what safe, risk-assessed modifications to the circulation system or drill string can be made to safely reduce wellhead pressure or flow rates to manageable levels.

22.8.6 Shutdowns

Shutdowns involve taking a dynamic, flowing well to a static, shut-in condition while remaining within the target downhole pressure range.

IRP Written procedures shall be available that detail the transition from flowing to static regardless of the cause of the shutdown.

IRP Potential shutdown scenarios should be reviewed and have mitigating procedures established during planning. Some possible scenarios are listed in Table 7.

Table 7: Possible Shutdown Scenarios

Scenario	Examples
Planned Shutdowns	• Ceasing drilling and preparing the well for a trip to change BHA components such as MWD tools, Logging While Drilling tools or a bit • Tripping -out and preparing the well for completion or suspension operations
Unplanned Shutdowns	• Simple mechanical failure of a circulation pump or compressor (i.e., blown pop valve, washed head/liner/valve, loss of suction) • Erosion of a choke manifold or a process piping element • Wear and usage cause change out the RCD sealing element • A washout or twist-off encountered in the drill string • Power failures or rig power generation issues

Closing primary flowline ESD valves increases the risks to the rig and rig floor personnel.

IRP Risks associated with the use of primary flowline ESD valves shall be assessed, controlled and mitigated as part of the risk assessment for the operation.

IRP An ESD valve closure shall be considered a well control event.

A well control event requires immediate closure of the rig BOPs according to a MPD/UBD specific shut-in procedure. See 22.12.2 Primary Flowline Emergency Shut-Down Valve.

Recommendations and requirements for emergency shutdown are provided in API RP 92M and API RP 92U.

See also 22.17.1 Unplanned Shutdowns.

22.8.7 Fire and Explosion Hazard Management

Flammability hazards are present in MPD/UBD operations. The Energy Safety Canada Fire and Explosion Hazard Management Guideline is recommended as the primary

source for fire and explosion hazard management information. The flammability hazards specific to MPD/UBD are noted in the Risk Register.

IRP MPD/UBD service providers shall have a hazard management plan that includes mitigations for fire and explosion hazards.

IRP All RMD/MPD/UBD operations shall have a flame arrestor or other regulator-approved backflash prevention mechanism in the RMD/MPD/UBD flare line.

IRP A bypass system should be included.

IRP Check valves shall not be used as flame arrestors.

22.8.7.1 RMD/MPD/UBD Separator Not Purged Prior to Lighting Flare

The risk of fire backlashing from the flare stack to the RMD/MPD/UBD separator can be mitigated by ensuring positive pressure is present on all vessels. This can also be accomplished by having a flame arrestor system and/or a backpressure valve in atmospheric systems.

IRP The MPD/UBD pressurized separator shall be purged of air before lighting the flare.

IRP MPD/RMD atmospheric separators should be purged of air before lighting the flare.

22.8.7.2 RMD/MPD/UBD Separator Liquid Carry-over Into RMD/MPD/UBD Flare Line

There is potential for liquid carry-over from the RMD/MPD/UBD separator into the RMD/MPD/UBD flare line when drilling with a non-water based circulation system and/or when underbalanced drilling for liquid hydrocarbons.

IRP The fire and explosion hazard assessment shall include the consequences of liquid carry-over from the RMD/MPD/UBD separator into the RMD/MPD/UBD flare line.

IRP Local jurisdictional regulations for flaring and venting must be followed when deciding whether to light the flare pilot or cold vent.

See AER D060: Upstream Petroleum Industry Flaring, Incinerating, and Venting for more information.

22.8.8 Flaring, Venting and Conservation

Extraneous sweet or sour gases may be expelled as part of regular MPD/UBD operations. Although these expelled gases may not be considered a beneficial part of

the drilling operation they do offer an alternative source of energy. The first course of action should always be to consider conserving gas into existing pipeline infrastructure. If gas cannot be conserved then flaring or venting is the final option.

Flaring is intended to reduce environmental impact and ensure public safety by burning extraneous gas produced by MPD/UBD operations. It is the licensee's responsibility to ensure that on-site contractors minimize flaring volumes.

IRP Flaring and venting must adhere to local jurisdictional regulations.

IRP Local jurisdictional regulations regarding air quality must be adhered to.

Air quality exceedances can be predicted with air quality dispersion modelling.

See the Energy Safety Canada Fire and Explosion Hazard Management Guideline for more details about fire/explosion risk mitigation.

Local jurisdictional resources can be found in Appendix K. A good reference is AER Directive 60: Upstream Petroleum Industry Flaring, Incinerating and Venting.

22.8.8.1 H_2S Content

IRP H_2S shall not be vented.

IRP Gas flaring containing H_2S must follow local jurisdictional regulations. A Flare Management Plan may be required.

Examples of flare management plans include the following:

- Downwind mobile air monitoring (measuring in the parts per billion (ppb) range)
- Remote sulphur dioxide (SO_2) monitoring
- Wind speed/wind direction or stability class restrictions
- Time of day flaring restrictions
- Combinations of the above.

22.8.8.2 SO_2 Content

Combustion of flared raw gas results in a conversion of H_2S to SO_2 as illustrated in the following:

$H_2S + O_2 + Heat = SO_2 + H_2O$

SO_2 is a dangerous compound. Flaring allows SO_2 to be more easily dispersed into the atmosphere.

IRP Local jurisdictional regulations for ground level concentrations of SO_2 must be adhered to.

22.8.8.3 Gas Volumes

IRP Local jurisdictional regulations for flaring volume or volume allowance threshold for sweet or sour gas must be adhered to.

22.8.8.4 RMD/MPD/UBD Separator Gas Carry-under Down the Liquid Shipping Lines

IRP The fire and explosion hazard assessment shall include the consequences of gas carry-under from the RMD/MPD/UBD separator into the liquid shipping lines.

22.8.8.5 Air introduced into circulating system

Oxygen is one of the components of the explosive triangle. Its presence is required as a fuel source for ignition. When the circulating system is open to atmosphere, such as during a drill pipe connection or tripping, oxygen from ambient air may act as an ignition source.

IRP Oxygen should be removed from the system to mitigate the likelihood of flammability hazards.

Oxygen can be eliminated prior to operations by purging all lines and vessels with an inert gas such as nitrogen. Oxygen can continue to be eliminated from the circulating system with a similar gas during operations.

22.9 Environment and Public

Environment and public considerations are a crucial part of the preparation of a MPD/UBD program and need to be part of the planning process. Local jurisdictional regulations must be consulted.

22.9.1 Hazard Assessment

An effective hazard assessment ensures mitigation measures are in place for the protection of workers, the public and the environment. It is an imperative part of any well program. See Appendix C for a suggested Hazard and Risk Assessment Process.

IRP All scenarios posing high risk to workers, the environment or the public shall be hazard assessed.

The Risk Register identifies several possible scenarios. Site and job-specific hazards also need to be identified and assessed. Hazard assessment for MPD/UBD scenarios is determined by the release rate of potential porous and permeable formations.

All provinces have their own legislation and regulations regarding the environment and public. Resources can be found in Appendix K. The following are two good references:

- AER Directive 56: Energy Development Applications and Schedules
- AER Directive 71: Emergency Preparedness and Response Requirements for the Petroleum Industry

IRP All RMD/MPD/UBD operations must adhere to local jurisdictional regulations pertaining to the environment and public safety.

22.9.2 Emergency Preparedness

IRP An appropriate emergency contingency plan must be prepared according to local jurisdictional Occupational Health and Safety regulations prior to any RMD/MPD/UBD operation.

The Operator is responsible for the emergency preparedness of all personnel on location. This includes scheduling, facilitating and documenting emergency preparedness and egress drills.

IRP All RMD/MPD/UBD operations must have an Emergency Response Plan as outlined in local jurisdictional regulations.

IRP During sour UBD operations, additional monitorable barriers should be used.

Additional monitorable barriers may include the following:

- Rovers working 12-hour shifts, 24 hours per day, in all rover areas inside the EPZ.
- Two public safety coordinators working 12-hour shifts to direct the rovers, along with downwind air monitors during normal sour operations from the remote command post.
- Public safety coordinators who establish strong relationships with residents within the EPZ and field inquiries or complaints received from the public.

Local jurisdictional resources can be found in Appendix K. For information on critical sour refer to IRP 06: Critical Sour Underbalanced Drilling.

22.9.3 Public Concerns

Public concerns and complaints are best avoided by establishing and maintaining ongoing relationships with surrounding residents. Operators are encouraged to be proactive and keep surrounding residents informed of operations that may impact their land, environment and/or persons.

IRP All RMD/MPD/UBD operations should consider and risk assess the impact of fugitive emissions, noise, increased lighting, road dust, road safety and groundwater contamination.

Consider the following:

- Noise levels from large flaring operations.
- Noise levels from multiple diesel engines from membrane nitrogen generation systems.
- The increased light from large or ongoing flaring operations.
- The increased light from extensive onsite lighting required for worker safety during night-time operation.
- Increased vehicular traffic and road dust of complex operations.
- Conflicts with residential seasonal traffic (e.g., school buses, farm equipment).

The risk of fracturing the formation below the shoe then contaminating groundwater is more prevalent in an MPD scenario where the MPD section is being drilled below surface casing.

Local jurisdictional resources can be found in Appendix K.

Refer to CAPP Best Management Practice for Fugitive Emissions Management for more information.

22.10 Minimum Recommended Experience and Training

IRP The operator shall be responsible for ensuring their assigned Wellsite Supervisor and the contractors/service providers are competent to complete the job.

IRP Personnel training, experience and competency shall be recorded.

IRP Each contractor or service provider shall ensure their personnel have the required skills and knowledge for the job.

Refer to IRP 07: Competencies for Critical Roles in Drilling and Completions for information about competencies and assessment of competency.

22.10.1 Personnel Experience Recommendations

Not all RMD/MPD/UBD operations are equally complex. Less complex RMD/MPD/UBD operations do not require personnel with experience in complex situations.

IRP If the driller is responsible for both rig controls and operation of the MPD choke/control system, the following conditions shall be met:

- A documented agreement between the operator and the drilling contractor for the driller to operate the MPD choke/control system shall be in place.
- A documented risk assessment shall be completed. The risk assessment shall have participation by both the operator and drilling contractor.
- There shall be documentation of training and competency in the operation.
- The person operating the MPD choke/control system shall be trained and deemed competent in the operation.

22.10.2 Personnel Industry Certification Requirements

Industry needs to review and consider MPD or UBD training, certification and/or competency evaluation based on local jurisdictional requirements and available training.

IRP Any on-site MPD/UBD field engineer or senior supervisor position shall have applicable well control training.

See IRP 06: Critical Sour Underbalanced Drilling for personnel requirements appropriate to Critical Sour UBD operations - retired

Further information can also be found in API RP 92M and API RP 92U.

22.10.3Additional Technical Training Recommendations

Program-specific technical training and orientation is recommended prior to any MPD/UBD operation. This may be an extended pre-drillout safety meeting or a drill-well-on-paper exercise.

IRP A thorough review of the HSE plans for the operation should be included in all program-specific orientations.

IRP All personnel to be involved in the program should be required to attend comprehensive presentations.

These are frequently conducted off-site in advance of the operation.

Recommended training topics are listed in Appendix H. Organizations can use topics as a guideline for developing course outlines, curriculum and training.

22.10.3.1 Site Orientation

IRP Any personnel entering a petroleum site or camp facility should receive an orientation specific to the hazards, procedures and emergency response plans for that particular site.

IRP The operator must provide a site orientation by either the wellsite supervisor or another designated safety representative (as per OH&S regulations).

IRP Orientation training should be given to personnel scheduled for the upcoming operation.

IRP Unscheduled new arrivals should receive a brief onsite orientation presentation equipping those personnel with the required HSE knowledge specific to the MPD/UBD operation, including its applicable hazards and high-risk areas.

Site orientation presentations are frequently accompanied by a printed document (e.g., handout or booklet) for all personnel.

IRP Supporting documentation should provide details of the process description, equipment deployed, operating characteristics and hazards involved, PPE requirements and other HSE content.

IRP Personnel should be assessed to ensure knowledge transfer of the information presented.

Completed orientation assessments are commonly documented and filed by the Operator.

22.10.3.2 MPD/UBD Drills

RMD/MPD/UBD operations involve numerous routine Standard Operational Procedures (SOPs), which may be unfamiliar to personnel accustomed to conventional drilling and workover operations.

Such procedures may include, but are not limited to, the following:

- Installing/removing NRVs
- In-casing tests/Finger-printing/Equipment Calibration
- Making MPD/UBD connections
- Changing out RCD elements
- Switching between primary and secondary flow paths
- Stripping
- Snubbing
- Well control techniques and handover (UBD Operations Matrix, MPD Operations Matrix, RMD Operations Matrix)

Proper execution of SOPs is critical to site safety.

IRP On-site drills should be considered if there are any concerns regarding crew experience.

IRP Practice trials should be conducted in a non-threatening condition, preferably prior to drilling, and with the well standing cased (or with a minimum of two tested barriers in place) prior to penetrating the anticipated productive section.

IRP Practice exercises should verify the following:

- Crew procedural competence
- Communications protocols associated with the SOPs
- The effectiveness of the procedures

22.10.4 Operational Readiness Review

IRP Prior to executing the MPD/UBD operation the operator should review all aspects of the operation including the following:

- The well program for application of equipment (i.e., program is in place for application of equipment within its designated operating parameters).

- Wellsite Personnel Experience/Industry Certifications (see 22.10.1 Personnel Experience Recommendations and 22.10.2 Personnel Industry Certifications).
- Training. Prepare and present training as required, including Site Orientation, as recommended in Appendix H.
- SOPs for all operations, specifically equipment operation, for equipment risk management adequacy.
- The Risk Register.

Note: The above items are interdependent and should be considered together not individually.

IRP The operator shall ensure all identified risks and hazards are mitigated and controlled to ALARP and that ALARA is applied where required by applicable legislation, regulation or recognized technical standards.

IRP A completed project-specific and site-specific risk register shall be present on location.

22.11 Mechanical Wellbore Integrity

Mechanical wellbore integrity refers to the ability and reliability of the casing, cement and wellhead to contain fluids in use. With both UBD and MPD the wellbore system, casing, cement and wellhead are primary barriers and may have to act as a single pressure containment barrier.

When compared to conventional overbalanced operations, MPD/UBD operations place additional stresses on the casing, the cement and the wellhead. In particular, UBD wells may involve higher annular flow rates and wider pressure variation which exposes the wellbore to reservoir fluids and potentially to varying bottomhole temperatures or pressures.

Additional high-risk MPD/UBD phenomena which impact mechanical wellbore integrity are summarized in this section.

22.11.1 Downhole Shock and Vibration

If UBD is conducted with gasified drilling fluids there is an inherent reduced ability of the fluid to dampen downhole shock and vibration. A lack of a lubricious filter cake across the permeable formation face and/or the presence of gasified fluids in the annulus can lead to higher torque during drilling, higher drag on trips and problems working weight down to the bit. Consider drill string design which aligns with increased drag/torque requirements.

These factors can create increased contact between the casing and drill string causing higher wear conditions within the wellbore. Increased wear may also occur in the drill pipe.

IRP Planners should consider more frequent drill pipe inspections on long term UBD projects.

22.11.2 Contact Wear

Contact wear occurs as a result of interaction between the casing and the drill string. It is usually monitored by using a ditch magnet in the return fluid stream. The degree of wear on the drill string and BHA components can be interpreted by the amount, or type, of steel filings attracted to the magnet.

IRP Casing wear should be monitored during UBD operations and/or accounted for in the casing design.

Consider casing friendly tool joint hardbanding or other measures as deemed appropriate if there are concerns about casing wear.

22.11.3 Minimize Wellhead/Upper Wellbore Damage

IRP Every effort should be made to minimize the possibility of wellhead or upper wellbore damage. Consider the following:

- Ensure the traveling-block/top-drive fall is aligned to the wellhead/stack/RCD.
- Run a lockdown style wear bushing to protect the sealing areas in the wellhead. Lockdown is preferred vs. non locking, as the wear bushing may lodge up into the BOP stack components during high flow rates.
- Include wear bushing positioning and retrieving in operational procedures.

22.11.4 Wellhead Design Considerations

IRP MPD/UBD applications should be reviewed with the wellhead vendor to ensure that the wellhead meets the additional demands of MPD/UBD operations.

22.11.5 Changing Wellbore Integrity

A risk analysis of wellbore integrity and possible changes through the operation is essential. Consider the various ways wellbore integrity could be lost. Once potential failures are identified the well design should accommodate and mitigate risks by assessing each situation individually.

MPD offers the potential advantage of extending open hole sections or eliminating a casing string completely. Typical MPD practice drills with reduced drilling fluid weight allowing annular fluid friction and retained wellhead pressure to maintain circulating bottomhole pressure marginally above formation pressure. Annular MPD pressure gradients are less than that of conventional weighted muds so greater pressure is imposed on casing seats when applying backpressure on surface for BHP control while drilling.

IRP Well designers shall continuously analyze and consider the changing formation conditions (i.e., pressures, temperatures, flow rates) to ensure equipment design limits are not exceeded.

The MPD practice of reducing drilling fluid weight and replacing it with in-hole friction and surface annular backpressure also affects Maximum Allowable Casing Pressure (MACP) calculations.

MPD is commonly used to eliminate intermediate casing strings.

IRP When no intermediate casing strings are used, consideration should be given to any additional well control procedures that may be required due to the fact that only surface casing is set (e.g., kick tolerances, MACP).

22.11.6 Regulatory Compliance

IRP Wellbore integrity concerns during MPD/UBD operations must be addressed considering local jurisdictional regulations.

Some specific scenarios are as follows:

- Are proposed operations being conducted with only surface casing set?
- Is the operation proposed for intermediate casing set in the well?
- Is the operation proposed for a re-entry into an existing wellbore?

22.11.6.1 New Installations

Refer to Appendix K for regulatory resources.

22.11.6.2 Re-Entry Wells

Refer to Appendix K for regulatory resources or IRP 01: Critical Sour Drilling (Re-Entry Wells section).

Note: IRP 01 recommendations apply to both new casing and existing casing in re-entry wells.

IRP For a re-entry well, a casing wear evaluation shall be conducted.

IRP Design must adhere to local jurisdictional regulations (e.g., AER D010: Minimum Casing Design Requirements and D056: Energy Development Applications and Schedules).

Casing collapse, tension and burst specifications are described in IRP 01: Critical Sour Drilling (Casing Design and Metallurgy section).

22.11.6.3 Casing Integrity

For a general overview and discussion on casing integrity in MPD/UBD applications see API RP 92U.

22.11.6.4 Cement Integrity

For recommendations regarding cement integrity for MPD/UBD situations refer to IRP 06: Critical Sour Underbalanced Drilling.

22.11.6.5 Open Hole Sections Above the Target Zone

For recommendations regarding open hole sections above the target zone refer IRP 06: Critical Sour Underbalanced Drilling.

MPD/UBD wells routinely see higher casing seat pressures than in conventionally-drilled holes. Some UBD wells may require that shut-in reservoir pressure be retained. Estimates of the range of possible downhole pressures under the various likely operating conditions can be derived from multiphase or hydraulic simulators or can be provided by the MPD/UBD service provider.

22.11.6.6 Wellheads

For recommendations regarding wellheads used in MPD/UBD applications refer to the following:

- IRP 05: Minimum Wellhead Requirements
- IRP 06: Critical Sour Underbalanced Drilling

22.12Well Control Equipment

The nature and amount of surface equipment needed for a MPD/UBD program depends on the magnitude of surface pressures, the method of pipe rotation, the nature and produced volume of the reservoir fluids anticipated and the type of drilling fluid system in use.

IRP MPD/UBD operations shall have a well control system which meets the following criteria:

- Allows drilling to proceed while controlling annular pressure.
- Allows connections while the well is flowing or shut-in.
- Allows tripping of the drill string under pressure.
- Provides for backup annular control in case of a RCD failure.
- Provides a means to bleed-off pressure or method to kill the well independent of the RCD.
- Provides a means to quickly and safely shut-in the well.

Additional information can be found in the following resources:

- AER Directive 36: Drilling Blowout Prevention Requirements and Procedures
- API RP 92M
- API RP 92U
- The PFD's in Appendix F and related text in 22.6 Process Flow Diagrams

22.12.1Blowout Preventer Stack

Well control equipment commonly used for RMD/MPD/UBD operations is primarily designed for conventional well control. MPD/UBD operations occur in a harsh environment that exposes the BOP stack to erosion.

IRP BOP parameters shall be documented and reviewed before starting the RMD/MPD/UBD operation (e.g., pressure rating, maximum closing pressure of the components).

IRP The Operator shall discuss and document the limits of the BOPs when closing against wellbore pressure, particularly (but not limited to) the annular preventer.

IRP The BOP stack should, at minimum, include the following components:

- A RCD with outlet for a flowline to the RMD/MPD/UBD separation package installed on top of the conventional BOP stack.
- A primary flowline from the BOP stack with nominal internal diameter (ID) of at least of 76 mm.
- An equalizing line (not required for RMD operations).

IRP Equalization and auxiliary equipment set up should consider the following:

Ensure there are no threaded outlets on the RCD for flow, equalization or pressure measurement.

- Provide the ability to equalize pressure around annular BOP.
- Provide the ability to equalize pressure around every BOP component (e.g., pipe rams, blind rams, annular).
- Provide the ability to bleed-off trapped pressure between any BOP stack components or ensure a contingency plan is in place to deal with trapped pressure.
- Provide the ability to measure pressure below the lowest ram at all times during the operation.

  Note: A redundant pressure measurement device is recommended below the blind ram if possible. Provide the ability to measure the pressure above and below any closed BOP component. See 22.7.1 Optional RMD/MPD/UBD Equipment for more information.

- Ensure equalizing and bleed-off lines are a minimum 50.8 mm nominal diameter.
- Hard lines are recommended for equalization. If using hoses, ensure the hoses are acceptable for equalizing and bleed-off lines and are properly certified for the working pressure of the BOP stack. Additional issues regarding flexible lines may include securement (e.g., in the event of movement on pressure application), fire guard rating and pressed-end connections requirement (e.g., flange or appropriate hammer union only, no threaded ends).
- Plan well control operations to use only the rig choke manifold.
- Set up the BOP stack configuration so that flow can be diverted from the primary flowline to the secondary flowline by opening one valve and closing one valve.
- Provide the ability to verify flow piping does not accumulate debris.

IRP Bleed-off or equalization lines shall only be used for its designed purpose.

IRP Well control BOP equipment shall not be used for stripping, snubbing or drilling except in emergency situations and for the following specific MPD/UBD operations:

- To permit maintenance of the RCD or to change RCD elements.
- To use a blind ram to isolate the wellbore when out of the hole with the drill string, and to lubricate in and out of irregular drill string, completion string or suspension string assemblies.
- To hang-off drill pipe in BOPs to service BOP/RCD equipment.
- To stage non-RCD strippable components in or out of the wellbore.

IRP The addition of drill string hang-off flanges is permitted within the BOP stack but shall be positioned above the uppermost ram type preventer.

If warranted, a set of blind/shear rams may be included in the stack in place of blind rams. Ensure the shearing capabilities for all BHA/drill string components within the BOP stack are known and understood prior to attempting shearing function.

IRP Drilling with returns taken through an outlet other than the RCD outlet flow spool or a fit-for-purpose primary flowline installed above the uppermost device shall not be performed.

Flow from below a closed BOP component or the lowermost BOP component is permitted only to allow pressure equalization, for flow/removal of gas heads or pressure during tripping operations or for RCD servicing operations.

IRP Flow periods shall be minimized when flowing under any BOP components.

IRP RCD to blind ram distance/length shall be compared to all BHA lengths to ensure that the well can be safely shut in after tripping to surface without the risk of blind ram contact/damage when closing.

22.12.2 Primary Flowline ESD Valve

Primary flowline ESD valves have typically been used to isolate the UBD surface separation equipment from the underbalanced well in the event of a separation equipment failure. Safety concerns regarding the use of ESD valves in the primary flowline exceed the benefits because the hazard is shifted upstream of the ESD valve to the RCD.

Primary flowline ESD valves are not recommended for sweet UBD operations because if the ESD is shut in the RCD could rapidly exceed its design pressure. For sour operations refer to IRP 06: Critical Sour Underbalanced Drilling.

If the primary flowline is placed above the annular preventer and a surface separation problem occurs, the annular preventer should be used to shut in flow from the well rather than using a primary flowline ESD valve. Any unplanned situation which requires

shutting-in flow from the well is classified as a well control event and should be handled primarily by the rig crew and drilling rig well control equipment.

IRP If an ESD valve is to be used in the primary flowline a risk assessment shall be completed to address the following:

- Well control interface to the rig's BOP system.
- Anticipated pressures and flow rates relative to equipment design limitations.
- The presence of single-phase or multi-phase fluids in the well during an ESD valve event and associated response times.
- The likelihood and impact of ESD valve closure (accidental or intended) which increases hazards to rig floor personnel.
- The use of fail-close ESD valves.
- The possibility of a pipe light condition or failure of the RCD due to activation of the ESD valve (depending on the situation).

IRP The rig floor shall be automatically alerted to an ESD valve activation to shut-in the well on the rig's BOP. Automatic alerts can be audio and/or visual.

See 22.6.4 BOP Configurations for information about BOP recommendations and integration with the rig's well control equipment.

IRP The rig's HCR and choke system must remain connected to the BOP stack and functional as per local jurisdictional regulations while drilling underbalanced.

This allows the well to be isolated with the annular and well kill operations to proceed using the rig's well control equipment.

Note: API RP 92U recommends the use of ESD valves for any well capable of natural flow to surface. Consult API RP 92U if the plan includes the use of an ESD valve. See also 22.17 Unplanned Operations or Events.

22.12.3 Rotating Control Devices

The RCD is a safety critical item for both MPD and UBD operations. It provides a seal at the uppermost part of the well system to divert annular flow to processing and measurement equipment. It also prevents any surface release of returning fluids to help maintain a safe environment on the rig floor. During MPD/UBD operations, the RCD is a primary containment device.

The RCD, most particularly the RCD element, is the weakest component in an MPD/UBD system. All operations with the device require special attention to ensure any

situation that could potentially shorten the element's service life is eliminated or minimized.

IRP MPD/UBD operations shall adopt a no-leak policy for the RCD.

IRP RCD servicing should be considered if operations have caused wear on the RCD or if wellbore pressure is likely to increase in future planned operations. See 22.16.5 Servicing the RCD Element for more information.

IRP The annular BOP should be capable of closing and sealing when the wellbore pressure is sealed-in above the annular.

Without the RCD, the annular preventer (particularly wellbore pressure-assist models) may be rendered inoperable by operations such as snubbing or situations where ESD valve closure has trapped pressure above the annular. Depending on the position of tool joints or other drill string components with irregular shapes relative to the pipe rams, closing the BOP may negatively impact well control functionality of the BOPs. This can be an issue in applications such as low-pressure oil wells or low flowing pressure gas wells but it is not insurmountable, especially with pipe ram backup to the annular.

Refer to the manufacturer's specifications for static, dynamic, and stripping pressure ratings.

IRP A risk assessment shall be completed for RCDs that do not meet API Spec 16RCD and/or local jurisdictional regulations.

IRP RCD element temperature rating should be known and reviewed against the maximum temperature (static and dynamic) expected during the operation.

IRP RCD devices should all have dynamic and static pressure ratings.

IRP The RCD shall remain within the operational limits defined by the manufacturer's specification.

Note: The dynamic ratings apply to pressure maximums that the RCD can handle while drilling and tripping, usually with a maximum allowable RPM. The static rating is the maximum allowable pressure the RCD can contain with no pipe movement.

IRP Dynamic pressure ratings can vary significantly with RPM. The stripping speed should be limited by the stripping pressure rating of the RCD.

IRP The chosen RCD shall have a static pressure rating greater than the maximum anticipated surface backpressure during RMD/MPD/UBD operations.

Once pipe has moved through the RCD, the maximum rated pressure of the RCD is no longer guaranteed. Pressure ratings for RCDs are a guide and are not be used as absolute values when pressures approach rated values. Select RCD element materials based on the expected drilling fluid system.

IRP Compatibility testing should be performed if there is any question about compatibility of the element materials and the fluid from the well, the circulation system, or any of the individual chemical additives (including chemical lubricants and defoamers).

Compatibility testing is particularly important if a high aromatic-content base oil is being considered or if elevated flow temperatures are expected. Pressure testing may be required prior to resuming operations to re-qualify the RCD as a barrier element after redressing the bearing and/or RCD element.

IRP Regular inspections of the control unit and its operability shall be completed.

IRP Any indication of RCD system failure shall be investigated and the appropriate action taken (e.g., communication with driller to shut in well to replace failed element).

Note: Depending on failure severity, drilling may continue.

IRP O-nsite redundant RCD backups should be considered.

The working seal in the RCD can be damaged by the following:

- Drill pipe roughness or connection grooves.
- Hardbanding that is not flush.
- A square or hex kelly.
- Sharp edges on kelly and kelly savers with rubber inserts (sharp edges can severely damage the RCD rubber).
- Transiting connections too rapidly through the element.
- Misalignment of the traveling block fall and rotary table.
- Chemical incompatibility with chemicals in use.
- Strip jars and/or bumper subs.
- Tool joints that have sharp angles.

IRP If a Kelly is required, it should be a hex Kelly rather than a square Kelly.

When tripping, worn RCD elements may allow minor gas/fluid release when connections pass through. Even new elements can have problems handling diameter changes from

the pipe body to pipe connections and especially if connections are being passed through the device too rapidly.

IRP The wear on the RCD element should be monitored via various indicators (e.g., fluid escaping, pressure, and sound) while stripping in and out.

Consider replacing bearing assemblies prior to operations where an unplanned change significantly increases risk (i.e., when surface pressure is necessary as a primary well control element).

IRP Personnel should be kept off the floor when reciprocating pipe.

IRP Automatic slips should be used for connections.

IRP The following items should be addressed prior to start-up:

- Review BOP stack drawings and interface with rig.
- Inspection of the rig BOP annular upper flange and bolting to ensure proper bolt engagement to annular flange body and damage-free gasket sealing area.
- Confirm drill pipe size(s) to be used are as per program.
- Confirm that a suitable grade of sealing elements has been selected, they are in the correct sizes and are on site in appropriate quantity.
- Confirm that the RCD is the correct model specified in the drilling program and that it meets the following job specifications:
    - Pressure rating (static/dynamic)
    - RPM rating
    - Maximum through-bore diameter with and without the bearing section installed
    - Temperature
    - Height
    - Element elastomer suitability for intended service, including fluid compatibility at the rated temperature
    - Clear height from the top of the annular to the bottom of the sealing element on the RCD
    - Clear height from the top of the blind rams to the bottom of the sealing element on the RCD

IRP The following should be completed prior to start-up to minimize the potential for premature RCD element wear or RCD failure:

- Confirm the vertical rig alignment and alignment with the center of the wellbore. Correct it if it is outside the guidelines of the RCD operating manual.
- Inspect the drill pipe for condition, pipe upset, connection grooving, etc. Confirm that it is suitable for the job without causing excessive RCD element wear.

IRP All critical procedures shall be documented. This includes the following:

- BHA deployment through the RCD.
- Changing the RCD element.
- Bleeding-off pressure below the RCD and equalizing pressure with the wellbore.
- Ensuring the MPD/UBD Operations Matrix and RCD pressure limitations are communicated in safety meetings and posted in the dog house, command center, MPD/UBD control unit, etc.
- Ensuring RCD elastomer elements have been stored appropriately.

  Note: Controlled-climate storage situations are best.

- Ensuring element drag figures are determined, including both pipe and connection passage through the RCD.
- Wellhead wear bushing selection.

  Note: Wellhead wear bushings may not fit through either the element or the RCD body with the element installed. They have to be chosen to fit through the RCD with the bearing or sealing element removed.

Active RCDs include pre-charged surge bottles which assist with the passage of connections through the closed element.

IRP The pre-charge pressure should be used and verified periodically throughout the use of the RCD.

Connections passing through the RCD element can cause considerable elastomer tearing and premature failure of the element.

IRP The supplier-specified equipment parameters shall be used when passing connections through the RCD.

IRP The bowl of the RCD shall have an ID equal to or greater than the diameter of the BOP stack.

Consider the following:

- Outside diameter (OD) of the wear bushing
- ID of the BOPs if it is necessary to access the BOPs for emergency scenarios
- OD of casing packer, plugs or tools required to isolate the wellbore (if necessary)

RCD elements usually handle diameter changes well but may have difficulty adapting to a smaller diameter after prolonged use on tools with larger OD.

See 22.6.7 Rotating Control Device and Primary Flow Line in the Well Control section for more information.

22.12.4NRVs

NRVs, or float valves, ensure the well cannot flow to surface through the drill string. They allow connections to be made more efficiently while the drill string remains pressurized below the NRVs. NRVs may be wireline retrievable or in-string subs.

NRVs are installed as near to the bit as possible. Deploying NRVs high in the drill string (termed Near-Surface NRVs or NS-NRVs) allows more efficient connections (i.e., the entire string does not require bleed-off to connect a new stand).

IRP If wireline retrievable NRVs are used, the associated wireline equipment and procedures shall be risk assessed.

Some models of in-string sub NRVs require installation of a keeper sub above the NRV sub. This allows pressure bleed-off below the valve so it will not launch when the connection below the keeper/top sub is broken.

Multiple NRVs are installed in the BHA. Near-surface NRVs (NS-NRVs) may be used to make connections more efficient.

IRP Installation, bleed-off and removal of NRVs should be included in practice trials because of the critical nature of these operations.

IRP Contingency procedures shall be in place to handle leaking NRVs.

Landing nipples in the drill string, either to land a pump-down internal BOP or to run a wireline-landed blanking plug, may also be considered for subsurface well control equipment. Such devices can provide a contingent backup should the NRVs leak.

IRP Operations that incorporate an internal BOP or wireline operation should be risk assessed.

IRP NRV bleed-off equipment shall have a pressure rating equal to or greater than that of the BOP stack.

IRP A minimum of two NRVs shall be installed as close to the bit as possible or directly above the drilling motor.

One of the devices can be a profile nipple designed to accommodate a pump-down back-flow device. These two NRVs are to be classified as barrier elements and part of the primary WBE because they are a mechanical barrier to the well.

IRP When gas is injected through the drill pipe and an NRV needs to be pulled to the floor, bleed-off procedures and equipment shall be used to remove trapped gas below the float before being removed from the string.

Integrity testing while bleeding off an NRV at surface only confirms integrity to the next NRV in the drill string.

IRP Integrity testing shall be repeated for all NRVs removed from the well.

IRP Contingency procedures shall be in place in the event of drill string integrity test failure.

IRP Operational procedures shall specify actions to be taken in the event that NS-NRVs or near-bit NRVs fail to hold pressure.

IRP For critical operations such as sour UBD, NRVs should be pressure tested before being installed in the drill string for the first time and after any rebuild.

IRP In UBD and air drilling applications, NS-NRVs should be spaced apart in suitable intervals to avoid an excessive number of NS-NRVs in the string and avoid excessively long connection bleed-off times.

IRP Screens should be used on the pump suction and above the MWD tools to prevent scale and solids from plugging NRVs and other BHA items or damaging the sealing surfaces.

IRP All adhesive labels should be removed from downhole tools. They may become detached in the hole and could plug downhole components.

NRVs, and the possible presence of energized fluid below the valve, are routine in UBD operations.

IRP Installation, bleed-off and removal procedures should be included in UBD onsite practice training as tool application differs substantially from conventional operations.

IRP The bleed-off hose connected to the NRV bleed-off tool shall be secured, or hard-lined, to ensure bleed-off is directed away from the floor and potential migration routes. Relieve pressure into the MPD/UBD separator for high pressure and into atmosphere for low pressure.

Additional information regarding NRVs and practices can be found in API RP 92U.

22.13 Surface Circulating System

The surface circulating system allows the well to be circulated conventionally using the drilling unit's equipment, using installed additional MPD/UBD gear or a combination of both. The MPD/UBD gear may include additional fluid circulation pumps and a provision for pressurized gas. It will include flowlines, chokes, separators, flare stacks, surface tanks and other devices to contain, control, monitor and process annular returns from the wellbore and injection into the well throughout the operation.

It is critical to strictly follow the P&ID during the rig-up of the gear on site because the system represented by the diagram is the scenario that has been risk-assessed.

IRP Upon completion of MPD equipment rig-up, verification that the rig-up has been done in accordance with the P&ID should be done.

IRP If the situation changes as a result of not being able to comply with the P&ID, a new P&ID shall be created and risk-assessed.

For additional information on PFDs refer to 22.7 Process Flow Diagrams.

22.13.1 Piping

Piping refers to all installed flow conduits including the following:

- Injection lines into the well via the standpipe.
- Flowlines tying into the rig's well control system.
- Flowlines directing annular returns to MPD/UBD chokes upstream of degassers.
- RMD/MPD/UBD Separators or other fluid processing equipment including solids control, component exit lines from process to storage, flaring in the case of flammable gases, or return to the pumping system or disposal.

IRP The primary flowline, secondary flowline (if present), equalizing line and any other piping exposed to wellhead pressure, including the line to the separation system, should be designed and tested for a working pressure greater than the potential maximum shut-in surface pressure and constructed in accordance with IRP04: Well Testing and Fluids Handling.

IRP Pressure ratings for other conduits should be designed and tested to exceed anticipated exposure pressures.

IRP Flowline design shall be based on maximum flow rates and pressures but not be less than ID of 76.0 mm.

IRP Flowline nominal diameters of 152.4 mm or larger should have flanged connections.

Lines with smaller nominal diameter may use hammer union ends providing the end connection is welded to the pipe.

IRP A routine maintenance and inspection program for the line should be in place (as per IRP 04: Well Testing and Fluids Handling).

Directional changes increase the potential for erosion and increase friction drop in the line section. Diameter reductions increase velocity which also increases the potential for erosion.

IRP In general, piping runs should be as straight as possible, with minimum direction changes and ID reductions.

IRP The MPD primary flowline must contain targeted tees (turns) or crosses blocked on fluid turns.

Other operational considerations on installed piping systems include the following:

- Quick or Weco® unions (i.e., 2” and 3” Fig 602, 1002, 1502 high pressure hammer unions) are nearly compatible with multiple threads and may fit multiple nuts over the male stub—this is a recognized safety hazard. IADC Safety Alerts, specifically SA 99-33 and SA 98-01.
- Ensure equalization around valves and other closure mechanisms is possible.
- Plan for circulation interruptions. Consider using a surface sub which will allow circulation from the standpipe to the drill string directly without the need to go through the kelly or top drive.

22.13.2 Chokes

IRP An MPD/UBD choke manifold shall be installed downstream of high pressure piping leading from the RCD outlet flange.

The choke should be used to control annular wellhead pressure as needed and to reduce pressure on the annular returns from the well in advance of the fluid processing equipment.

IRP The choking system should have a pressure rating above the maximum designed operational shut-in surface pressure.

Both MPD and UBD technologies involve solids in well returns and UBD wells involve entrained gases. The presence of solids and the mechanical restrictions involved with choking increases the possibility for erosion in choke internals and immediately downstream of the choke.

IRP The choking system configuration should include isolatable dual legs to allow for component change-outs in the event of erosion or other disabling events (e.g., hydrate formation).

API RP 92U recommends the ID of piping downstream of a choke manifold be larger than upstream piping.

Erosion is possible. Erosion calculations are required in API RP 92U. API RP 92U references a method for estimating multiphase erosional velocities documented in API RP 14E. It also recommends the use of a second choke manifold be considered for gas wells with potential for flow above the capacity of the RMD/MPD/UBD separator in order to step-down pressures more gradually than possible with a single manifold along with the use of highly erosion resistant chokes.

Note: API RP 14E does not take drill cuttings into consideration.

If entrained gases are involved in the well returns, choking of flow may result in a temperature drop sufficient to cause gas hydrates to form and/or result in temperatures below the operability rating of the equipment. This can plug chokes and other process equipment, make components inoperable and cause materials to brittle fail.

IRP The probable range of temperatures and pressure returns from the well should be evaluated to determine if hydrate formation is possible and if component/material ratings could be exceeded.

IRP If hydrate formation is possible the choke manifold should be equipped with facilities for chemical injection (e.g., usually glycol or methanol) to dissolve hydrate plugs or prevent hydrates from forming. Line heaters should also be considered (see 22.5.9 Hydrate Risks).

22.13.3 Standpipe Bleed-Off

The standpipe bleed-off line is used to bleed down the standpipe injection header. This reduces standpipe pressure to permit connections.

IRP The following should be considered for the standpipe bleed-off:

- Install a high-pressure bleed-off to the RMD/MPD/UBD separator to allow for bleeding down to RMD/MPD/UBD separator pressure before bleeding down to atmospheric pressure.

- Low pressure bleed-off should be directed to a low-traffic area such as the rig's degasser or flare tank.
- The bleed-off area should be clearly visible with appropriate signage.
- The hazards associated with the bleed-off area (e.g., noise, high pressure gas, drilling fluid mist, potential combustible gas if floats are leaking) should be discussed at safety meetings.
- Bleed-off lines should be heat traced in winter to avoid freezing and ice plugs.

IRP A check valve shall be installed in the bleed-off line to prevent reverse flow from the separator to the standpipe/rig floor for MPD/UBD two phase operations.

For more information see API RP 92U.

22.13.4 Open Tank Systems

In open tank systems drilling fluids are exposed to air. Fluids returning from the well may have injection gas, formation gas and formation fluids in their makeup. Processing equipment will de-gas and retain, or remove, liquid hydrocarbons (dependent on whether an oil-based or water-based drilling fluid system is used) and return fluids to the pumping system for reinjection.

Open tank systems are of special concern because of the possibility of the release of combustible vapours (e.g., remnant gas passed along from the separation system).

IRP The following measures should be taken to avoid hazards with open tank systems:

- Eliminate sources of ignition near the tanks.
- Strictly adhere to the Canadian Electrical Code.
- Don't use open tank systems for sour well operations.
- Continuously monitor for explosive vapours, H_2S and oxygen-deficient areas.
- Review the Energy Safety Canada Fire and Explosion Hazard Management Guideline.
- Review IRP 14: Non-Water Based Drilling Fluids.

IRP A fire and explosion hazard management plan shall be developed and available on site (see 22.8.7 Fire and Explosion Hazard Management).

22.13.5 RMD/MPD/UBD Separator

Separation systems can range from atmospheric degassers (which remove only entrained gases) to sophisticated pressure vessels capable of separating solids, gases, and discrete liquids.

IRP The first stage of separation should be through a vessel certified by the appropriate local jurisdictional regulator.

IRP The design should be capable of completing the safe and efficient separation of liquids, gases and solids based on anticipated flow rates, pressures and RMD/MPD/UBD flare line size. If slug flow is anticipated, then RMD/MPD/UBD separator capacity should be increased to accommodate the increase in flow rate.

IRP RMD/MPD/UBD separation vessels and other process equipment shall be purged with gas prior to use to ensure explosive conditions are not present.

IRP Only non-combustible mixtures should be flowed through the RMD/MPD/UBD separator (normally this eliminates the use of air-type drilling fluid systems).

IRP All pressure vessels and production tanks shall be electrically bonded and grounded as per the appropriate local jurisdictional regulations.

IRP Pressurized MPD/UBD separators should be checked, cleaned, and flushed of solids prior to use.

IRP Multiphase flow modelling should be used to estimate the possible range of flow rates.

The simulations are based in part on reservoir information provided by the operator and are typically reviewed with technical and operational representatives of the service provider to determine the appropriate separation system. In the simulations, consider the possibility of reservoir flow characteristics being better than expected or bottomhole pressure being higher than expected.

IRP Simulations should be run over the range of possible conditions to determine the potential rates. This will establish the separation system capacity requirements.

See API RP 92U for more information.

22.13.6 Pump Lines (Liquid and Gas)

Liquid and/or gas injection lines for MPD/UBD operations are always downstream of the rig pumps.

IRP The pump lines shall have pressure ratings that are equal to or greater than probable pump maximum pressures and should be capable of handling anticipated flow rates with minimal pressure drop.

Consider including a high-pressure tie-in point to match the maximum predicted surface pressure if the pump pressure rating is lower than the well control system.

IRP Valves should be provided that can shut-off the gas supply and allow connections.

IRP Gas shall not be permitted to backflow from the standpipe to the pumps.

Check valves are preferred means for controlling the risk of undesirable and/or unplanned reverse flow.

In the case of mud pumps, if check valves are not installed between the mud pumps and the standpipe, ensure the mud pumps do not get gas-locked by starting the mud pumps first (i.e., prior to starting drill string gas injection).

IRP Check valves shall be used on gas injection lines.

IRP Gas injection lines should be equipped with a bypass to the MPD/UBD separator or /MPD/UBD flare line during connections to eliminate having to shut the compression equipment off when making a connection.

Refer to API RP 92U for additional recommendations for pump lines.

22.13.7 Additional Considerations for Influx Management in MPD Operations

IRP If influxes are circulated using MPD equipment, the system should be designed to handle such influxes. During the design phase, kick tolerance calculations should be made to determine the maximum influx volume that can be circulated using MPD equipment as per the MPD Operations Matrix or the Influx Management Envelope (Refer to API 92M A.4.5.8.) .

Note: API 92M Section A.4.2 provides equipment considerations to circulate influxes using MPD equipment.

IRP If MPD equipment will be used for influx circulation, a bypass for the flame arrestor should be considered in the event it becomes plugged.

22.13.8 Piping for RMD/MPD/UBD Flare Lines

An RMD/MPD/UBD flare line goes from the RMD/MPD/UBD separator to the flare stack or flare system. All considerations listed in section 22.8.7 Fire and Explosion Hazard Management apply to RMD/MPD/UBD flare lines.

In well control terminology, the line going from the mud gas separator to the flare line or system could be referred to as a vent line. In IRP 22, this line in the RMD/MPD/UBD system is referred to as the RMD/MPD/UBD flare line.

IRP RMD/MPD/UBD flare lines must comply with local jurisdictional regulations.

IRP An analysis should be conducted to determine the diameter of the RMD/MPD/UBD flare line to minimize backpressure in the RMD/MPD/UBD separator while circulating gas through the vent line.

IRP A continuous flare ignition system should be used (i.e., the pilot is continuously lit).

IRP The RMD/MPD/UBD flare line shall be self-draining or have drainage points.

IRP RMD/MPD/UBD equipment and well control equipment shall each have its own flare line and flare stack.

22.14 Drill String and Drilling Rig

22.14.1 Drill String Requirements

Drill pipe is a critical component to flow control on an MPD/UBD well. Pipe condition, both internal and external, can impact how other key components perform (most notably the RCD and the NRVs). External roughness or presence of connection grooves can markedly reduce service life of an RCD element. API RP 92U recommends filling in the grooves. Grooves may be filed down to extend RCD element life if practical. Internal scale, rust or other debris in the drill pipe or other elements of the BHA can plug NRVs. This can be particularly problematic with internally-coated drill pipe if the coating is starting to break down.

IRP **The risk assessment shall fully assess all consequences of drill string integrity failure (including all BHA components).**

See the following for more information:

- API RP 92U
- Section 22.12.3 Rotating Control Devices
- API RP 7G-2: Recommended practice for Inspection and Classification of Used Drill Stem Elements
- Standard DS-1®

22.14.2 Drilling Rig

Most MPD/UBD operations are conducted with conventional drilling rigs modified as necessary for the demands of the drilling program. Top drives are included in many drilling programs due to their efficiency but Kelly-drive rigs may also be used.

The vertical clearance between the top of the rig's BOP stack and the rotary table beams limits the space available for additional MPD/UBD RCD and accessories. In order to comply with the well control demands of the program and to be able to install the RCD, it may be necessary to install a smaller BOP stack which may in turn impact drill string and other component selections.

22.14.3 Rig Alignment

IRP The wellhead should be centred to the block fall and rotary table.

Failure to do so may result in premature RCD element failure. Misalignment may cause wellhead vibration which may back off studs and nuts if not properly torqued. Misalignment may also cause key seating, wellhead wear and/or casing wear from contact between the drill string and wellhead/wear bushing or casing.

IRP RCD shall be inspected daily and re-torqued as required.

See 22.12.3 Rotating Control Devices for more information about mitigating RCD failure.

22.14.4 Kelly Hose

MPD/UBD multi-phase operations frequently add membrane-generated or cryogenic nitrogen to the drilling fluid system to tailor fluid density for the program. Nitrogen under pressure tends to invade any elastomers exposed to the gas/liquid UBD circulation fluid. When pressure is reduced, nitrogen bubbles may form in the elastomer leading to delamination, weakening and potential failure. Suitably rated Kelly hoses made with materials more resistant to nitrogen invasion damage are available.

MPD/UBD operations may cause more wear on the Kelly hose. Consider the following:

- Debris can plug BHA components and cause failure.
- Energized fluids may be released.
- Temperature and pressure ratings need to be appropriate to the job.
- Circulated fluid needs to be compatible with the hose.

22.15Wellsite Safety

Wellsite safety describes minimum standards for site safety during UBD and MPD operations. The recommendations in this IRP supplement existing industry standards and regulatory requirements. In cases of inconsistency among any of the recommended practices contained in this IRP and applicable legislation, the legislative requirements prevail.

22.15.1 Location Planning and Preparation

MPD/UBD wellsites require additional equipment and site-specific resources significantly different than conventional drilling locations. Refer to IRP 20: Wellsite Design Spacing Recommendations for spacing guidelines.

Additional references include the following:

- IRP 04: Well Testing and Fluid Handling
- IRP 08: Pumping of Flammable Fluids
- IRP 14: Non-Water Based Drilling Fluids
- Energy Safety Canada Fire and Explosion Hazard Management Guideline

The IADC's Underbalanced and Managed Pressure Drilling Operations: HSE Planning Guidelines can be referenced in the construction and planning stages of any MPD/UBD project.

22.15.2 Lease Lighting

IRP **Traffic areas, both vehicular and pedestrian, shall have adequate lighting.**

IRP A means of emergency lighting (based on pre-job assessment) should be made available at the wellsite that allows personnel to

- leave the wellsite safely,
- initiate emergency shutdown procedure and/or
- perform a rescue.

Refer to the Energy Safety Canada Lease Lighting Guideline for more information.

22.15.3 Communications

MPD/UBD operations are inherently complex and require regular and consistent communication amongst all personnel involved (e.g., Driller, Rig Manager, Rig Crew, Wellsite Supervisor, UBD or MPD Supervisor and field engineers, geologists, etc.).

IRP Communication planning should include the following:

- Drilling the well on paper (DWOP)/Pre-spuds
- Pre job safety meetings/drill out meetings
- Onsite communication protocols.

22.15.3.1 Operational Concerns

IRP The drilling supervisor should arrange a daily supervisor's meeting during operations to review any problems encountered in the last 24 hours, discuss the forward program and attend to any other relevant information.

IRP If conditions change during the process of conducting the written program of work and/or the risk situation changes, the new situation shall be assessed with a new written work instruction prepared and approved before commencing the new work.

IRP Operational instructions, including a discussion of contingency procedures, shall be reviewed at a pre-job safety meeting prior to embarking on a new section of the program.

IRP A safety presentation (e.g., toolbox talks) should be offered immediately to any new crew that arrives. This initial safety presentation should include a discussion of the most current operational instructions.

22.15.3.2 Communication Systems

The level of noise from the general activity can make communication difficult.

IRP All operationally active personnel and organizations shall have instant voice access to each other (i.e., two-way radios).

Personnel involved include the following:

- Company supervisor/ wellsite supervisor
- Rig manager
- Driller
- Safety supervisor (if applicable)

- All applicable MPD/UBD personnel (e.g., nitrogen operator, air compressor operator, injection gas operators, surface separation system personnel, geotechnical specialists, directional drillers, etc.).

IRP The communications system should be capable of providing communications to all concerned personnel regardless of location or noise level. The following should be available:

- Intrinsically safe, hand-held UHF radio systems with a provision for headphones for personnel in high-noise environments.
- A sufficient number of radios, radio holsters, microphone attachments, recharging stations, etc.
- Microphones for one-hand operation.

IRP Risks and mitigations for communications system failure should be reviewed and prepared. Communications protocols should include the following:

- All personnel should perform radio checks with the driller when coming on tour.
- All personnel should note any operational dead spots and inform all other organizations.
- The driller should issue all orders for start-up and/or shutdown of injection gas and opening/closing of the flowline to surface separation facilities.
- All relevant events observed should be communicated to the driller.

22.15.4 Site Access and Security

IRP Dedicated security should be considered to control site access.

The degree of security can be determined depending on the complexity of the operation and the environmental and industrial sensitivities within the location. Some operators may require training prior to accessing the site.

IRP The main entrance to the lease shall be marked with appropriate warning signs indicating the following:

- Access is restricted
- H_2S gas may be present
- Any other hazards specific to the operation

IRP Only essential services personnel should be on site during MPD/UBD operations.

IRP **All visitors shall be given an orientation briefing before entering the lease area and visits should be kept as brief as possible.**

22.15.5 Wind and Gas Monitoring on Site

IRP Wind socks or flagging should be located on site to indicate wind direction at ground level and aid in establishing site-specific egress routes.

IRP The location and number of wind socks or flags should be sufficient to allow personnel at the various work stations to easily view the wind direction at all times.

Consider providing wind monitoring at the following locations based on a pre-job assessment:

- Gas separation unit
- Shale shaker
- Rig floor
- Mud mixing area

IRP **An H_2S monitoring program shall be in place if H_2S is expected in the well. At minimum, monitoring stations should include the following:**

- The rig floor
- Inside the rig substructure adjacent to the BOPs
- Near separation vessels
- Shaker box and circulating tanks

IRP Explosive potential monitoring should be conducted anywhere there is a potential to release combustible vapours to the atmosphere. Monitoring stations should include those indicated above for H_2S.

22.15.6 Emergency Egress

IRP **Egress routes shall be established that allow safe escape, under any wind conditions, in the event of a hydrocarbon release.**

IRP **Each egress route shall have a designated safe briefing area.**

IRP Planned egress routes should consider the following:

- Each wellsite should have a minimum of two personnel egress routes.

- Egress routes should not be downwind or downhill from a potential release.
- Equipment should be placed to ensure an unimpeded means of egress.

22.15.7 Confined Space Entry

The MPD/UBD separator may be the largest confined space entry challenge on the site. Other confined spaces include potentially oxygen deficient areas such as areas inside a membrane unit or compressor enclosure and areas at close proximity to other operating equipment.

IRP Operators must observe all OH&S regulations for confined space entry.

IRP All personnel conducting operations in confined areas shall be trained in confined space entry.

22.15.8 Pre-Job Orientation

IRP A site-specific orientation shall be reviewed with all onsite personnel involved directly in, or supervising, the operation prior to any work commencing on a MPD/UBD well (see WorkSafe Alberta's Pre-Project Meeting Guidelines).

IRP Documentation supporting this orientation shall be kept at the wellsite. Topics for review and discussion should include, at minimum, the following:

- Hazards involved (e.g., pressures, H_2S percentage, etc.).
- Site-specific equipment.
- Security.
- The procedures in place for planned and unplanned events (i.e., muster stations and lease egress).

Additional topics for discussion in more complex work can include the following:

- The site-specific ERP specifically addressing the alarms and the safe muster areas, search and rescue procedure (for sour UBD wells).
- The project plan.
- The location map and equipment layout including hazardous areas and identified safety equipment locations.
- The onsite organizational hierarchy and chain of command, worker roles (regarding safety critical/non-critical) and related responsibilities.
- Communications available (e.g., portable zone-rated radios, frequency, etc.).

22.15.9 Safety Meetings

IRP A site-specific safety meeting shall be conducted with all onsite personnel involved directly in, or supervising, the operation prior to the commencement of RMD/MPD/UBD operations.

IRP The topics covered in the safety meeting should be repeated with all operations personnel arriving for the first time since the commencement of MPD/UBD operations. Topics and persons attending should be appropriately documented.

IRP Regular safety meetings should be conducted with personnel directly involved in the operation or those residing on the wellsite. These regular meetings should provide updated information, instructions, policies and procedures or report any change in operational scope such as the introduction of new equipment, services, procedures or personnel.

22.15.10 Safety Equipment Requirements

22.15.10.1 Breathing Apparatus

IRP Respiratory protective equipment must be used in accordance with the appropriate jurisdictional Occupational Health and Safety regulations (e.g., in Alberta, OHS Code, Part 18: Personal Protective Equipment, Sections 244-254).

It is the operator's responsibility to assess the need for respiratory protective equipment, ensure it is available in sufficient quantity and ensure it is used appropriately by workers. For sour well locations ensure enough equipment is available for both regular operations and evacuation.

22.15.10.2 Fire Protection Equipment

Prepare fire protection requirements based on a risk and hazard assessment that includes the following:

- Fire protection for personnel egress
- Protection of drilling equipment
- Protection of existing facilities

22.15.11 PPE Requirements

No specific additional PPE requirements have been identified for MPD/UBD operations.

IRP At minimum, local jurisdictional Occupational Health and Safety regulations regarding PPE requirements must be adhered to along with the requirements from the MPD/UBD site-specific hazard assessment.

22.15.12 Lifting Hazards

Tie-in of RMD/MPD/UBD equipment to the drilling rig usually requires hoisting and lifting operations. Evaluate and document risks prior to hoisting and lifting any loads.

IRP Personnel immediately involved with picking up and positioning gear should ensure an unambiguous set of hand signals are clearly understood by the hoisting unit operator and the assistants handling the loads and slings.

IRP The drilling supervisor should ensure the following:

- All required lifting personnel certificates are current.
- Slings used are appropriate to the loads imposed.

All onsite personnel are cautioned to remain out of the immediate area and stay clear of suspended loads unless their presence is essential to the operation.

22.16 Operational Procedures

22.16.1 General Operational Considerations

During MPD Operations various factors can inadvertently effect the BHP and the ability to maintain the planned operating window, Points to consider stopping or replanning operations can include:

- Loss of communication between driller and MPD operator;
- tripping speeds (in relation to swab and surge) changes from tripping plan;
- changes to connection procedures/parameters;
- influx detection method and mitigating actions/procedures such as when to transition to conventional well control;
- changes to mud properties;
- available mud volumes, e.g. contingency volumes and pit volume management plan;
- any impacts to well control barriers; and
- contingency plans that could affect ability to operate MPD.

22.16.2 Concurrent Rig-Up/Out Operations

Depending on the site-specific requirements, rig crew and service company familiarity, rig-up/rig-out intervals may be short and relatively uncomplicated. Others may require more involved plans for equipment installation or removal.

The rig-up phase includes installation, pressure testing and commissioning of various services. It involves start-up operations including motors, pumps, compressors, etc. Start-up operations provide the opportunity to fault trace problematic items. The rig-up phase may be the first time onsite services have worked together

To avoid NPT, discuss all necessary items required for the installation with contractors prior to rig-up. Equipment is sometimes substituted at the last minute so there may be some variation between the PFD and the exact rig-up. The issued PFD is the intended rig-up and the one which has been risk-assessed.

IRP If the ultimate installation is different than the PFD issued for the program, differences should be risk-assessed and mitigations for any potential hazardous

situations mitigated before putting that individual segment of the process equipment into play.

IRP The on-site PFD shall reflect the exact rig-up.

Conventional drilling, completion activity or work on adjoining facilities may be proceeding while MPD/UBD equipment is rigged-in and commissioned for service. Concurrent execution activities can strain onsite services, disrupt routine worksite activity and potentially lead to increased hazard levels.

IRP A pre-job safety meeting should be held prior to commencing the MPD/UBD rig-up (see 22.15.8 Pre-Job Orientation and 22.15.9 Safety Meetings). The following should be emphasized:

- The need to conduct all operations safely.
- The circumstances that require suspension of operations (i.e., activities do not go as scheduled or the risk situation changes).
- Rig-up plan details (including pre-rig up site survey).
- Any other concurrent on-site activities.
- The overall safety plan.
- The chain of command.

Once all gear has been positioned and connected to the process stream as per the PFD, all valves in the rig-up may be identified with a waterproof tag. If used, the tag should use the same valve numbering system as the PFD.

22.16.3 Drillout/Hole Conditioning

22.16.3.1 Drillout Pre-Planning

Additional drillout pre-planning is required due to the complexities associated with a MPD/UBD operation. For example, during UBD operations where gas is added to liquid drilling mud, lifting capacity of the combined fluid is dependent primarily on liquid phase annular velocity. Annular cleaning problems (in particular casing shoe track drillout debris) can result from landing the last casing string too high relative to the drilled depth, creating a section of enlarged hole at the very top of the open hole where UBD operations occur. An enlarged hole may be difficult to clean adequately which creates an on-going problem for the program.

Select float equipment carefully for the last casing string before the MPD/UBD section. Consider the following:

- Gear with internal metal parts may damage drillout bits, particularly PDC models.

- Welded centralizers are more prone to bowspring loss. When using casing centralizers consider using devices that lock the bowsprings into the top and bottom collar.
- Casing float and centralizing gear suppliers should be informed of the following to safeguard operations as much as possible:
    - Bits and BHA planned for the drillout
    - Drilling fluid to be used
    - Any other constraints
- If drilling through casing that has an un-cemented interval, a specific risk assessment for loss of casing integrity needs to be completed during planning (see 22.11 Mechanical Wellbore Integrity).

22.16.3.2 Drillout and Pre-Penetration Drills

Practicing procedures ensures personnel are familiar with operations. There is an opportunity to train onsite personnel prior to drill out or penetrating the potential critical zone.

The following routine MPD/UBD procedures can be observed and practiced by drilling crews in a safe, non-threatening situation:

- Connection procedures for MPD/UBD
- Equipment fingerprinting and/or functioning
- Stripping pipe in and out with wellhead pressure using the RCD
- Installation/removal of the RCD, including element
- BOP and evacuation drills
- Handling ESD events (if ESD valve is installed)
- Handling specialized tools or equipment
- Kick Drill (MPD)

22.16.3.3 Well Control Considerations

MPD/UBD operations are carried out with the implicit understanding that the rig's BOP stack and well control system can be used to shut in safely. This is only true if the exposed formations can withstand the pressures involved.

IRP A formation integrity test shall be conducted before drilling ahead into the target horizon if there is any doubt about the integrity of the zone the casing shoe is set in.

The results of this test along with additional information (e.g., reservoir pore pressure) should be used to confirm planned well control procedures (e.g., hard shut-in vs. soft shut-in).

22.16.3.4 Displacing Hole to MPD/UBD Drilling Fluids

Shoe drillout is frequently accomplished with the drilling fluid used when the last casing string was run. If a tailored MPD/UBD multi-phase drilling fluid is planned it may not be tolerant of contaminants. In this situation the displacement of the existing drilling fluid in the well has to be carefully planned.

The following may require a displacement plan:

- Displacing the well from a single-phase to/from a multi-phase fluid
- Displacing the well from a single-phase fluid to/from a foam system
- Displacing the well from kill mud to/from lighter-than-conventional drilling fluid

Note: These plans may need to change during execution due to varying conditions.

22.16.4 Tripping/Stripping with Surface Pressure

During tripping operations, it is critical to prevent formation fluids from entering the wellbore as this can reduce the effectiveness of the primary well barrier which can result in a kick.

IRP Prior to starting tripping operations, company and/or rig specific procedures should be developed, documented, and agreed upon by all parties (operator, rig contractor, etc.)

IRP Clear direction for the steps involved in the tripping procedure should be provided in the drilling program, work instruction or other document to manage the risks specific to tripping operations. This should include but is not limited to:

- Shut in procedures.
- Contingency plans (e.g. evacuation plans)
- Kill sheets.
- Trip sheets.

Tripping can be done with pressure on surface without requiring snubbing but not beyond the pipe light depth. Tripping and stripping may be contingencies to conventional tripping procedures.

Pipe light occurs when the wellhead pressure acting over the cross-sectional area being sealed against exceeds the effective weight of the pipe in the hole. With the presence of annular pressure, there is the potential hazard of a pipe light condition developing.

Snubbing may be necessary if tripping pipe with positive wellhead pressure above the pipe light depth is required. Refer to IRP 15: Snubbing Operations for more information about snubbing.

IRP **Written procedures shall be in place for all routine operations including the following:**

- Trip-out of hole (if performed with pressure at surface)
- Trip-in hole (if performed with pressure at surface)
- Servicing the RCD element
- Determining the pipe light point
- NRV procedures for bleed-off and installation

Other prepared procedures may include the following:

- Pumping in/pumping out
- Displacing the drill string
- Well flow check
- Specific well kill procedures
- Interrupted service (i.e., liquid or gas disruption)
- Delays in resuming liquid circulation (i.e., change-out of saver sub or discovery of thread problems on next stand)
- Snubbing or other specialist procedures
- Stripping (backpressure schedule)

See 22.12.4 NRVs for procedures regarding NRV installation and bleed-off and 22.5.4.2 MPD Backpressure Management for guidance on establishing and controlling backpressure during MPD operations.

22.16.4.1 Trip-Out of Hole

Trip-out of hole includes all preparatory work for the trip-out as well as step-by-step procedures.

IRP Procedures should reference the PFD for valve operations, particularly if snubbing services are involved. Always consider contingency situations such as an interruption of services.

IRP Flow checks shall be performed during trips. Methods to perform flow checks in hydrostatically underbalanced conditions shall be included in the MPD/UBD program and defined beforehand. Unless otherwise stated by local jurisdictional regulations, flow checks shall be performed:

- prior to starting tripping operations,
- at the deepest casing shoe,
- prior to removing the RCD sealing assembly and
- before pulling BHA components across the BOP.

IRP Flow checks should follow conventional practices once the well has been killed (e.g., trips where a kill mud has been pumped to bring the well to a hydrostatically overbalanced condition).

22.16.4.2 Determining the Pipe Light Point

The pipe light condition only occurs when surface backpressure is positive. This section assumes that surface backpressure is applied during the tripping operation.

IRP The possibility of pipe light shall be identified in advance and crews shall be provided with a clearly outlined "do not hoist past point" value. MPD/UBD operations shall not cause the pipe light condition.

IRP "Do not hoist past point" value shall be included in the drilling program and include a safety factor considering maximum pressure on surface.

Evaluation methodology for determining pipe light conditions is available from snubbing contractors and in IRP 15: Snubbing Operations.

22.16.4.3 Trip-In Hole

Trip-in hole includes all preparatory work for the trip-in as well as step-by-step procedures. Procedures need to reference the PFD for any necessary valve operations.

22.16.4.4 Swab and Surge Effects

Swab and surge refer to pressure effects in the wellbore that occur when moving the drill string (or casing) up or down in the wellbore. Swabbing is the reduction in bottom-hole pressure when the drill string is pulled upward. Large bottomhole pressure reductions can occur when swabbing takes place and is one of the major reasons for losing primary well control.

When a drill string is pulled from a well, swabbing can be difficult to detect. The well must be filled with fluid as the drill string is pulled out of it. If the fluid required to fill the well is less than the pipe displacement volume of the pulled string, the formation fluid

may have swabbed into the well. Detection of swabbing can only be done by accurately measuring the drilling fluid added to the hole as pipe is pulled.

Effective measures to prevent swabbing can be put in place when the prime factors that cause swabbing are understood.

- Balled bit or BHA components.
- Pulling pipe too quickly.
- Poor drilling fluid properties (e.g., high viscosity).
- Reduced wellbore geometry (annular clearance) caused by either swelling formations or large OD BHA components.

22.16.4.5 Kick Indicators

IRP If a kick is suspected, the well shall be secured and further analysis shall be carried out to confirm the presence of the kick and the appropriate next actions required.

IRP If the well does swab despite using best tripping practices, the pipe should be run back to bottom and the well circulated to get bottoms up.

IRP The following warning signs while tripping or while making connections shall be considered for all trips:

- Increased flow or flow after pumps are stopped
- Trip gas
- Connection gas
- Well fill after a trip
- Changes in fluid returns, e.g. temperature and density.
- Increased overpull or "tight" well on connections
- Wellbore not taking the correct amount of drilling fluid to compensate for pipe displacement volume

22.16.4.6 Wellbore Breathing

Wellbore breathing (generally referred to as ballooning) occurs when a volume of mud is lost to the formation during circulation, but some or all of it flows back when circulation stops. Ballooning can be mistaken as a sign that a kick is occurring in the well.

IRP The impact of ballooning should be assessed prior to the start of tripping operations and monitored throughout.

The main impacts to tripping operations include the following:

- Additional rig time (NPT) spent interpreting readings and trying to diagnose the issue
- Misinterpretation of a kick, which can lead to applying incorrect procedures; using standard well control procedures during a ballooning event can worsen the situation
- Compromised integrity of the primary barrier (drilling fluid) when the hydrostatic pressure is very close to the formation pressure

Steps to identify ballooning include the following:

- Monitoring fluid returns; accurate monitoring of flow back data from the well (fingerprinting) is key to identifying ballooning
- Maintaining an accurate trip sheet
- Monitoring fluid volume changes in the trip tank

Steps to mitigate ballooning include the following:

- Ensuring the drilling fluid has consistent properties (e.g., mud weight, rheology)
- Performing a pressure step-down test; if wellbore breathing is suspected as the cause of the drilling fluid flowback, a pressure step-down test can be conducted by opening and closing the choke. The shut-in pressures are expected to decrease after each shutdown step due to reduced formation closure stress.
- Conducting a continuous bleed-down test; this type of test will show a continuing reduction in pressure and flow rate if the cause of the initial shut-in pressure was from wellbore breathing.

22.16.5Servicing the RCD Element

If operations require continued flow, flow can be diverted through the equalizing line or a secondary line (if present) if the line is designed to accommodate wellbore flow.

IRP The equalizing line shall be independent of the rig's choke manifold.

IRP Flow through the equalizing line shall not be permitted during drilling.

All procedures need to reference the PFD for necessary valve operations.

IRP A double-block-and-bleed procedure and a gas purge shall be used when servicing sour operations.

Double isolation allows for monitored, redundant isolation from sour fluids.

IRP The well shall be shut in when servicing the RCD in sour operations. Sour fluids need to be flushed from the system prior to removing the RCD bearing.

IRP An integrity test shall be performed upon completion of RCD servicing. At minimum, the RCD should be in-flow tested to the current wellbore pressure prior to removing isolation.

Proactive RCD servicing and/or element replacement should be considered prior to the pipe light point and/or stripping of BHAs out of the hole.

22.16.6Pressure Equalization

Many MPD/UBD procedures include specific valve closing or opening, both planned and unplanned. Closing some elements of the BOP stack is likely necessary at some point in the MPD/UBD operation. After closure a pressure differential usually exists across the valve or stack element closed. Pressure equalization has to be achieved across the closed element before it can be opened and returned to service.

IRP Qualified on-site personnel shall carefully consider how to pressure equalize following closure of a valve or stack element.

Substantial pressure differential between the zones to be equalized may make operation of the equalizing line isolations difficult and stack elements can be damaged or rendered inoperable by sudden pressure release.

IRP Proper planning, risk assessment and documented procedures shall be in place for pressure equalization operations.

For equalization procedures refer to IRP 15: Snubbing Operations.

22.16.7 Managed Pressure Cementing

Managed Pressure Cementing (MPC) is the application of MPD techniques, principles, and equipment to cementing operations. Like MPD, MPC utilizes the application of SBP to precisely control the annular pressure profile during static and dynamic conditions with monitoring for signs of influxes or losses. However, during the placement of the cement slurry, it is more critical to ensure an overbalanced condition to minimize influxes and losses so that the cement provides the required zonal isolation.

22.16.7.1 Considerations

IRP MPC jobs should be risk assessed prior to the job.

MPC jobs can start in or enter a hydrostatically underbalanced condition. MPC jobs are listed below in order of increasing risk for loss of well control and the unintentional cementing of equipment:

- Jobs that transition to a hydrostatically overbalanced condition prior to cement arriving on surface or landing the top plug
- Jobs that end in a hydrostatically overbalanced condition but require the displacement of some cement through the MPD equipment.
- Jobs that end in a hydrostatically underbalanced condition that require the application of SBP at the time the top plug lands on the bottom plug.

The risk of influxes with MPC is higher than conventional cementing. Kick circulation after landing the top plug is not possible.

IRP Well control should be considered as part of the risk assessment for MPC jobs.

22.16.7.2 Planning

IRP The key depths, their pressure constraints, and the time and pump rate constraints of the cement should be considered during the planning of an MPC job and as needed, reevaluated based on observed drilling conditions.

IRP MPC hydraulic modelling should target staying within the drilling window.

IRP Hydraulic modelling should identify conditions where cement free fall and/or U-tube effects might occur and a flow-in/flow-out mismatch might occur.

IRP Hydraulic model results provided by the cement provider and the MPD provider should be aligned.

IRP There are many additional uncertainties associated with typical cementing operations which cannot always be accounted for by hydraulic models but should be considered during the planning phase. These include:

- Potential of changing open hole geometry during cementing (e.g., pack-offs, hole breakdown)
- Uncertain mixing of fluids and associated blended rheologies at interfaces
- Pipe eccentricity and fluid channeling
- Absence of downhole pressure measurement
- U-tube effects

Casing and liner strings often use pressure activated downhole tools. Premature activation of these tools can be detrimental to well control; the risk is increased in MPC scenarios.

IRP Downhole tool pressure deployment parameters shall be identified and compared to planned MPC operational parameters.

IRP The casing or liner string should be well defined to identify components with larger or complex geometry that may cause increases in Annular Friction Losses (AFL) during the cement job. In tight annulus spaces around liner hanger, polished bore receptable (PBR), packer, mandrel, etc., the accuracy of frictional pressure loss models for cementing could be uncertain.

IRP Due to frictional pressure loss model uncertainties, adjustments should be made as necessary during job execution.

In addition to drilling fluid rheology, cementing fluid rheology is critical for hydraulic modeling purposes to ensure downhole pressure is maintained within the drilling window so influxes are prevented and losses are minimized.

IRP In high temperature, narrow margin environments, temperature effects on mud, spacer and cement density at placement depth should be considered.

IRP Spacer and cement properties shall be characterized in advance of any final MPC hydraulic modeling. Such properties shall be tested considering downhole conditions.

IRP For elevated risk MPC operations, a pre-job tabletop exercise or simulation shall be conducted to review anticipated pressure responses, abnormal scenarios, and decision authority.

22.16.7.3 Equipment

MPC can be completed with either standard RCD sealing elements or with larger bore casing stripper elements.

IRP Consideration should be given to the altered pressure performance of a casing stripper compared to an RCD sealing element.

IRP The displacement of cement through MPD equipment should be avoided. A contingency procedure for flushing MPD surface equipment with a fluid that prevents cement hardening should be developed in cases where cement is circulated through the MPD equipment.

MPC casing cementing operations can be conducted using several wellhead configurations. The following IRP statements apply when a solid body mandrel hanger is used during MPC operations.

IRP A risk assessment should be completed before conducting MPC operations with a solid body mandrel hanger. The assessment should address wellhead design, the return flow path through the wellhead, and well control barriers.

IRP When a solid body mandrel hanger is used, the MPC lines and wellhead valves shall be pressure tested before the MPC operation begins.

IRP When a solid body mandrel hanger is used, erosion should be minimized during the MPC operation. Returns should be as free of cuttings as practicable, for example by circulating the well clean before the hanger is landed.

IRP When a solid body mandrel hanger is used, the MPC lines shall be sized for the expected flow rates and return conditions of the MPC operation.

IRP If an MPC operation with a solid body mandrel finishes in a hydrostatically underbalanced condition, the MPD equipment shall be used to contain annular pressure until the pressure is stable (i.e., not increasing over time). Once the MPC operation is complete and annular pressure is stable, the wellhead lateral valves can be used as pressure-containing devices.

IRP If the annulus remains pressurized after the MPC operation, the completions team should be notified of the pressurized annulus, for example through handover documentation and tagging of the wellhead valves.

IRP When a solid body mandrel hanger is used, at least two valves shall be installed on each wellhead outlet used for returns during the MPC operation.

IRP When a solid body mandrel hanger is used, additional independent valves shall be available in the MPC lines to shut in the well during or after the MPC operation, if required.

22.16.7.4 Execution

IRP MPC hydraulic modeling should be followed for the placement of the cement during regular operations until the top plug is landed or a hydrostatically overbalanced condition is achieved. Responding to losses (and gains) should take precedence over the Surface Back Pressure schedule developed by hydraulic modelling.

IRP A proper contingency plan should be in place to define the course of action in case of influxes or losses of circulation.

During MPC operations, communication is critical to prevent accidental influxes.

IRP Cementing personnel and MPD personnel shall have a direct line of communication during MPC operations.

IRP Expected and unexpected pump rate changes during cementing shall be communicated to all parties involved.

IRP Key cementing and MPD sensor data should be continuously monitored and communicated to the electronic data recorder (EDR) system.

During MPC operations, there is an increased likelihood of trapped pressure in the casing or liner string (pumping lines and/or cementing head). This trapped pressure can result in HSE events.

IRP The effect of trapped pressure in the cement head or pumping lines during operations shall be considered and mitigated if needed.

Pressure may need to be maintained on the well after the top plug is landed to maintain an overbalanced condition, to monitor for unexpected flow, or aid in the setting of the cement.

IRP Personnel involved in MPC planning and execution shall participate in a pre-job meeting covering pressure management principles, failure modes, and contingency response.

22.17 Unplanned Operations or Events

IRP Plans should be in place for the following emergency or unplanned operations:

- Drill string failure (e.g., washout, NRV/float failure)
- RCD failure
- Separation system failure (e.g., flowline washout, carry-over, etc.)
- Circulation system failure (e.g., mud pump, gas injection system, etc.)
- Fire
- Rig system failure (e.g., Kelly hose, draw works/top drive, etc.)
- Stuck pipe
- Lost circulation
- Wellhead leak
- Loss of well control (e.g., blow out)
- Plugging (in drill string, BHA, bit, downhole tools)

See the Risk Register for more information and areas to consider.

22.17.1 Unplanned Shutdowns

Unanticipated events will occur. Without adequate preparation for the unexpected the results will be unpredictable. Operators and service providers are encouraged to document all technical and operational lessons learned from each unanticipated event to share with industry and feed back into the Risk Register (See Appendix C: Hazard and Risk Assessment Process for details). The accumulated lessons form an experience base and best practices for future training and improvement initiatives.

IRP **A risk assessment shall be completed for any unplanned shutdowns to ensure potential new hazards are identified. This shall include any additional emergency shut-down systems (e.g., emergency shutdown (ESD) valves, positive air shut-offs, etc.).**

22.17.2 Unplanned Oil/Condensate Production

Unanticipated oil or condensate production may be encountered during MPD/UBD operations. For example, in the case of a water-based drilling fluid the surface separation system may be unable to discretely separate the condensate from liquid returns. With oil-based drilling fluids condensate may absorb into the oil phase of the mud system importing naturally-occurring chemicals which can adversely affect designed drilling fluid properties including fluid density.

IRP **If unanticipated condensate or other liquid hydrocarbon production is encountered and if its presence increases risk, those increased hazards shall be appropriately addressed before proceeding.**

This may require suspending operations until suitable mitigations to the new situation are in place.

If condensate or oil production is high enough it may create on-site storage problems and additional onsite hazards (e.g., greater surface fluid volume present then can be stored in the available facilities). Offsite fluid transportation may be required which presents additional hazards and HSE concerns. These scenarios should all be risk assessed.

In air drilling operations, produced liquid hydrocarbons can substantially change explosive limits which can lead to mud-ring formation and/or possible auto-ignition. Don't use air as the circulation fluid if unanticipated liquid hydrocarbon production is possible. See 22.18.1 Air Drilling for information about air drilling.

22.17.3 Drill String Failure

Drill string failures are encountered in conventional operations (generally a washout or a twist-off of a component in the drill string or BHA). With the well in an overbalanced condition, as long as other complicating situations such as a well control, lost circulation or drill string/BHA plugging incident are not occurring at the same time, a typical solution involves tripping-out to replace the washed-out element or tripping prior to fishing to recover and replace lost items before drilling ahead.

With MPD/UBD operations, energized fluid in the annulus and/or the presence of wellhead pressure complicates the initial reaction to drill string failure. Wellhead pressure acts on the cross-sectional area being sealed by the RCD or BOP which exerts an upward force on the drill string. This upward force is resisted by the weight of the drill string below the sealing element and by the mechanical drag of the piping components across the sealing element itself.

A pipe light condition can occur rapidly in the event of a shallow twist-off. In these situations, the physical weight of the remaining equipment above the twist-off point is less than upward forces from the pressure-area product of the wellhead pressure and the sealed cross-sectional area.

IRP Written procedures shall be in place to allow operational personnel to diagnose and react appropriately to drill string failures.

22.18 Other Operations

22.18.1 Air Drilling

IRP The hazards and risks associated with flammable and/or explosive mixtures shall be identified and addressed when planning to use air in a drilling fluid for MPD/UBD operations.

One possible alternative to reduce oxygen levels is to add cryogenic or membrane nitrogen to a sufficient level to prevent explosive mixtures.

22.18.1.1 Hazards

For well control the primary concerns with downhole fires and explosions are:

- The risk of shutting-in a well which allows it to build pressure and cause an explosion.
- The potential for parting the drill string above the drill string floats.
- The risk of casing failure.

Mud rings are a problem in air drilling and can severely limit or entirely pack off the available space for flow which leads to rapid escalation of downhole pressure. If there are any combustible hydrocarbons in the downhole mixture, this can lead to auto-ignition where the mixture spontaneously combusts causing BHA burn-off and downhole fires.

Well control issues can result for the following reasons:

- If downhole detonation destroys the NRV devices in the string.
- If the explosion separates the string above the NRVs.
- If the installed casing or its cement integrity is involved.

Mud rings are caused by water influx from the formation. If mud rings are present the drilling techniques will need to be altered (e.g., switch to foam/two-phase applications).

If hydrocarbons are present, discontinue the use of compressed air as circulation fluid immediately to mitigate risks of downhole fires, explosions or uncontrolled release of potentially explosive mixtures.

IRP Pressurized separation systems shall not be used for air drilling operations.

IRP Cold venting of the returning gas phase (sweet gas only) should be used to avoid fire/explosion ignition source risks.

IRP Site-specific dispersion modelling shall be conducted to ensure the flammable plume above the vented area does not pose explosion and/or flammability hazards.

22.18.1.2 Recommended Practices

Air drilling operations use RCDs to isolate returns to surface. Since surface pressures are usually low they usually involve lower pressure devices than seen in UBD or MPD. Lower-pressure RCDs may be appropriate as long as the device's manufacturer supports the particular application and testing has been completed and documented to prove its reliability over the specific range of pressures.

IRP Air drilling operations shall have two non-ported NRVs (floats) near the bottom of the drill string.

Ideally, these NRVs should be positioned in the last stand of BHA to be removed from the well. A profile nipple can be used to accommodate a pump-down back-flow device on top of the NRVs.

Air drilling usually involves diverting the air, drilled cuttings and any formation inflow to a atmospheric flow-back tank.

If the air drilling includes bringing annular returns back through a separator it is important to ensure that only non-combustible mixtures are involved and explosive limits in the return line are monitored when drilling fluids include oxygen.

IRP Explosive limits shall be established for circulating fluids that can introduce oxygen into the circulating system.

IRP Systems which could introduce oxygen shall not be used if explosive limits are not clearly defined.

IRP Explosive limits shall be documented and posted next to the oxygen monitoring system for all circulating systems that contain oxygen.

IRP Monitoring stations should include the rig floor, inside the substructure next to the BOP stack and near separation vessels, storage tanks and circulating tanks.

IRP All hydrocarbon influxes should be logged. A chromatograph and/or in-line gas detection device (e.g., LEL) is recommended.

IRP All gas influxes should be checked for H_2S. The well should be circulated to a kill fluid immediately if any H_2S is detected.

The impact of H_2S to the flammability limits (e.g., LEL and UEL) is unpredictable during reservoir inflow flush production events.

IRP Air drilling operations shall be terminated upon detection of any level of H_2S.

IRP Diverter line to flare pit (tank) systems should only be used for drilling intervals where no hydrocarbons are present or for drilling sweet natural gas wells (e.g., air, air-mist, foam drilling media). For these systems the following apply:

- Reservoir liquids can not be directed to the flare pit.
- A continuous purge of the diverter line should be conducted during circulation, start-up and shut-down and when making connections.
- All returns have to be cold vented to the atmosphere to reduce risks associated with a flare pilot being an energy-ignition source (see the Energy Safety Canada Fire and Explosion Hazard Management Guideline).

IRP The following areas should be addressed in the operational plan to reduce the HSE impact of air drilling:

- Cuttings containment
- Dust suppression (may include water mist)
- Containment of wellbore fluids
- Waste disposal
- Noise suppression (may be required in populated areas)

It is safety critical to avoid pressure build-up within the well when the wellbore is known to contain hydrocarbons and air.

IRP Crews shall be trained in soft shut-in well control practices and familiarized prior to starting air drilling operations (see also 22.16.6 Pressure Equalization).

If the blind rams are used to isolate the wellbore when no pipe is in the hole, ensure operational practices prevent the build-up of pressure in the well when the blind rams are closed and the wellbore is known to contain hydrocarbons and air.

The following sections of API RP 92U provide a general overview and discussion of air drilling:

- Media Properties
- Operational Guidelines
- Breathing Air/Gas Detection Equipment
- Debris accumulation in the BOP stack can compromise BOP integrity and operability.

IRP The operator shall assess the risk of debris accumulation in the BOP stack.

API RP 92U recommends cleaning out dust from BOP cavities at least once per 24 hours for air drilling.

IRP BOPs should be cleaned prior to function testing.

22.18.1.3 Hazard Management

IRP A gas detector measuring methane content, UELs and LELs must be installed in the return line in accordance with local jurisdictional regulations.

IRP Site-specific dispersion modeling shall be conducted to ensure the flammable plume above the vented area does not impose explosion and/or flammability hazards.

IRP Designs shall consider the possibility of encountering liquid hydrocarbons and/or coal.

The well control practice of soft shut-in (i.e., rig choke is always open) may be used until the fire/explosion risk conditions in the well allow for a complete hard shut-in. (See 22.18.1.2 Recommended Practices regarding shut-in training during Air Drilling).

IRP Air drilling designs should also consider the following:

- Use an atmospheric tank.
- Avoid backpressure to the well with the primary flowline and separation system (i.e., no choke manifold or shut-off valves).
- Don’t allow the wellbore pressure build to the point flammable/explosive conditions exist. Operators planning air drilling operations with potential for natural gas inflow should be familiar with the Energy Safety Canada Fire and Explosion Hazard Management Guideline.

- Cold vent the returning gas phase to avoid fire/explosion ignition source risks (sweet gas only).
- Use a de-dusting pump to avoid hazards associated with dust. Optional chemical injection systems may be considered for foam drilling operations.

22.18.2 Coiled Tubing

The MPD/UBD state can be maintained with greater assurance when continuous circulation via coiled tubing is combined with a choking and separation system at surface. Pipe handling hazards are reduced due to the minimal drill string connections. A coiled tubing rig can also trip pipe much faster with a well control BOP/stripping stack and an integrated snubbing unit specialized for the technology.

On a coiled tubing project the IRP 22 hazard assessment process is still appropriate as many of the hazards and risks remain (see Appendix C: Hazard and Risk Assessment Process).

Refer to IRP 21: Coiled Tubing Operations for more information on coiled tubing operations.

Appendix A: Revision Log

The revisions to IRP 22 are logged in the following table.

Edition 4

Edition 4 of IRP 22 involved a limited scope review of the IRP to align with updates to API 92M regarding influx tolerance and mitigation as well as MPD training. Specific changes are highlighted in the table below.

Table 8. Edition 4 Revisions

Section	Remarks and Changes
General	Updates to current IRP template: • Disclaimer • Range Update Enform to Energy Safety Canada • Range of obligation terminology • Revision log/acknowledgments • Moved definitions and acronyms to an Appendix for Glossary (Appendix J) • Terminology and style updates to match current IRPs and DACC Style guide
22.2.1 Definitions	Added term “RMD/MPD/UBD Flare Line” to clarify terminology specific to RMD/MPD/UBD systems.
22.3.2 Non-Routine Operations	Added IRP statement clarifying that influx management using MPD equipment is considered non-routine and requires inclusion in the risk assessment.
22.5.3.1 MPD Operations	Revised section to: • Clarify definition of drilling window limits to include hole stability limits in addition to pore and fracture pressures. • Expand discussion of consequences of incorrect pressure estimation, including hole collapse risk and impact on surface equipment capacity during influx circulation. • Updated cross-reference to MPD Operations Matrix (section 22.8.5.2). • Added IRP statement identifying operational factors that may require stopping or re-evaluating MPD operations, including changes in fluid properties, communication breakdowns, tripping/connection changes affecting swab and surge, kick detection and transition criteria, reduction in fluid volumes, changes to well barriers, and other events affecting the ability to operate within planned system limits.

Section	Remarks and Changes
22.5.4.1 MPD Operations	Updated section to: • Strengthen requirements for diversion to the rig well control system by revising language from “should” to “must” when MPD Operations Matrix limitations (including kick intensity) are exceeded. • Clarify and specify MPD equipment requirements for Dynamic Pore Pressure Testing (DPPT), including identification of MPD separator, MPD flare stacks, and MPD choke manifold where applicable.
22.5.4.2 MPD Backpressure Management	Updated section to add IRP guidance addressing stripping practices under MPD conditions, including swab/surge mitigation and monitoring of drilling fluid replacement volumes during tripping operations.
22.6 Well Control	Revised to: • Clarify terminology by replacing “planned limits” with “operating limits” when defining well control event thresholds within the Operations Matrix. • Add IRP statement for bridging documents to explicitly include MPD influx management considerations, including influx detection and circulation.
22.6.1 Barriers	Added two new IRP statements to recommend: • use of the BOP as a primary barrier during RCD bearing replacement be temporary • the BOP not be used for planned events in MPD operations and a risk assessment should be performed for remedial operations that require use of a secondary barrier
22.6.1.1 Well Barrier Objectives	Added a new IRP statement recommending both primary and secondary well barrier envelope function and equipment be clearly defined in the drilling program for MPD operations and barriers be established for all stages of a well’s life cycle. Minor wording corrections
22.6.2 Determination of Safe Operating Limits for Influx Management	Removed section 22.6.2 Well Kill Section and added new section added including subsections to formalize criteria for defining maximum influx volumes that may be managed using MPD equipment. Additions included: • Surface equipment pressure limits, including review of weakest component ratings, pressure test limits, and RCD element condition. • Downhole pressure limit requirements to ensure hydrostatic plus surface backpressure does not exceed fracture gradient. • Methodology for determining maximum allowable surface pressure during influx management using equipment limits, downhole limits, and safety factors. • Surface gas and liquid flow rate limitations based on MPD mud gas separator, piping, and surface equipment capacity. • Requirement to calculate maximum MPD influx volume limits, including static worst-case scenarios,

Section	Remarks and Changes
	and to incorporate these limits into the MPD Operations Matrix and Influx Indicator thresholds, with transition to secondary well control if exceeded.
22.6.3 Influx Detection, Control and Circulation Using MPD Equipment	New section added to establish guidance and requirements for managing influxes within MPD operations, including: • Requirement that the MPD system shall be capable of reliably measuring influx volumes when circulation using MPD equipment is planned. • Criteria defining when an influx is considered controlled (stabilized pit gain, zero delta flow, constant standpipe pressure) and requirement that influx control operations adhere to the MPD Operations Matrix pressure ranges. • Requirement that a pre-defined influx circulation procedure must be developed during planning when MPD equipment will be used for influx circulation, including provisions to transition to secondary well control if required. • Requirement that the influx must be deemed controlled prior to circulation and that surface equipment limits and circulation parameters be reviewed and monitored. • Inclusion of influx management plots to illustrate detection, arrest, and circulation processes.
22.8.5.2 MPD Operations Matrix	The MPD Operations Matrix was revised to: • Add header fields for Operating Company, Drilling Contractor/Rig ID, Well Name, Well Section and Mud Weight to improve site-specific applicability. • Clarify pressure and influx limit ranges by redefining threshold terminology (Planned Limit and Operating Limit) and associated decision boundaries. • Update matrix action statements to align terminology with revised limit definitions and improve clarity of required response when planned or operating limits are exceeded.
22.8.7 Fire and Explosion Hazard Management	Updated section to clarify terminology and align references with RMD/MPD/UBD systems by: • Updating flare line references to “RMD/MPD/UBD flare line.” • Revising subsection titles and content to explicitly reference RMD/MPD/UBD separators. • Clarifying liquid carry-over considerations specific to the RMD/MPD/UBD separator and flare line.
22.8.8.4 RMD/MPD/UBD Separator Gas Carry-under Down the Liquid Shipping Lines	Revised to clarify terminology by specifying “RMD/MPD/UBD separator” in both the section title and the IRP statement addressing gas carry-under into liquid shipping lines.
22.12.3 Rotating Control Devices	Revised to:

Section	Remarks and Changes
	• Clarify reliance on manufacturer specifications for static, dynamic, and stripping pressure ratings and require operation within defined manufacturer limits. • Add IRP guidance addressing dynamic pressure variation with RPM and limiting stripping speed to RCD stripping pressure ratings. • Add requirement to monitor RCD element wear indicators during stripping operations. • Update cross-reference for RCD element servicing (Section 22.16.5).lhkj k • Refine language regarding annular BOP functionality when sealed-in above the annular and clarify operational considerations when the RCD is not installed.
22.13 Surface Circulating System	Added IRP statement recommending verification that MPD equipment rig-up was completed in accordance with the P&ID.
22.13.5 RMD/MPD/UBD Separator	Renamed section from “Separator” to “RMD/MPD/UBD Separator” to clarify applicability to RMD/MPD/UBD operations by: • Updating terminology to reference RMD/MPD/UBD separator and RMD/MPD/UBD flare line. • Clarifying separator design expectations relative to RMD/MPD/UBD flare line sizing and slug flow capacity. • Specifying purging, non-combustible fluid handling, and inspection/cleaning requirements for RMD/MPD/UBD pressurized separators.
22.13.7 Additional Considerations for Influx Management in MPD Operations	New section added to: • Establish design expectations when circulating influxes using MPD equipment, including requirement for kick tolerance calculations to define maximum influx volume in accordance with the MPD Operations Matrix or Influx Management Envelope (APE 92M reference). • Require consideration of a flame arrestor bypass when MPD equipment is used for influx circulation.
22.13.8 Piping for RMD/MPD/UBD Flare Lines	New section added to establish terminology and requirements for RMD/MPD/UBD flare line design and operation, including: • Clarification of flare line terminology within IRP 22 and alignment with Fire and Explosion Hazard Management requirements (Section 22.8.7). • Requirement that RMD/MPD/UBD flare lines must comply with local jurisdictional regulations. • Requirement that flare line diameter be analyzed to minimize separator backpressure during gas circulation. • Requirement that a continuous flare ignition system be used. • Requirement that flare lines shall be self-draining or include drainage points.

Section	Remarks and Changes
	• Requirement that RMD/MPD/UBD equipment and conventional well control equipment shall have separate flare lines and flare stacks.
22.16.4 Tripping/Stripping with Surface Pressure	Updated section to formalize planning, procedural and well control recommendations for tripping operations under surface pressure conditions. Additions included recommendations for: • Documented and agreed-upon tripping procedures prior to operations, including contingency plans, kill sheets, trip sheets and shut-in procedures • Written procedure for routine and non-routine tripping activities (e.g., tripping in/out, RCD servicing, NRV procedures, determining pipe light point, stripping) • Flow checks during tripping, including considerations for hydrostatically underbalanced conditions. • Formalized pipe light identification and “do not hoist past point” including inclusion in the drilling program with safety factors • Guidance on swab and surge effects, kick indicators, wellbore breathing (ballooning), and mitigation/monitoring expectations • MPD-specific backpressure management including connection pressure management, use of PWD tools or calibrated hydraulics models, transition procedures between static and dynamic states, and consideration of casing seat pressures • Pre-planned procedures to address tripping with less-than-kill-weight drilling fluids, including swab/surge calculations and trip margin management
22.16.7 Managed Pressure Cementing	New section added to formalize application of MPD principles and equipment to cementing operations. Additions include: • Defined MPC and its distinction from conventional cementing, including elevated well control risk and inability to circulate a kick after landing the top plug. • Established risk assessment requirements and categorized MPC job types by increasing well control risk. • Added planning recommendations including hydraulic modelling within the drilling window, alignment between cement and MPD modelling, identification of pressure constraints, evaluation of downhole tool activation parameters, and consideration of open hole geometry, U-tube effects, cement/slurry rheology, and temperature impacts. • Required characterization and testing of spacer and cement properties prior to final hydraulic modelling, and mandated tabletop exercises for elevated-risk MPC jobs. • Equipment requirements addressing casing stripper performance, avoidance of cement displacement through MPD equipment, contingency flushing

Section	Remarks and Changes
	procedures, and conditions for the use of solid body mandrels during MPC operations. • Established execution requirements including adherence to hydraulic modelling, precedence of gain/loss response over SBP schedules, contingency planning for influxes/losses, continuous communication between cementing and MPD personnel, real-time monitoring of sensor data, mitigation of trapped pressure hazards, and defined pre-job meeting expectations for MPC operations.
Appendix F: Process Flow Diagrams	Process flow diagrams were updated to label MPD equipment.
Appendix G: Recommended Training Topics	Training tables were updated with MPD influx management topics including kick detection tools, flow out measurement, and backpressure.
Appendix K: References and Resources	Added a list of MPD-related recommended practices and specifications.

The following individuals helped develop this edition of IRP 20 through a subcommittee of DACC.

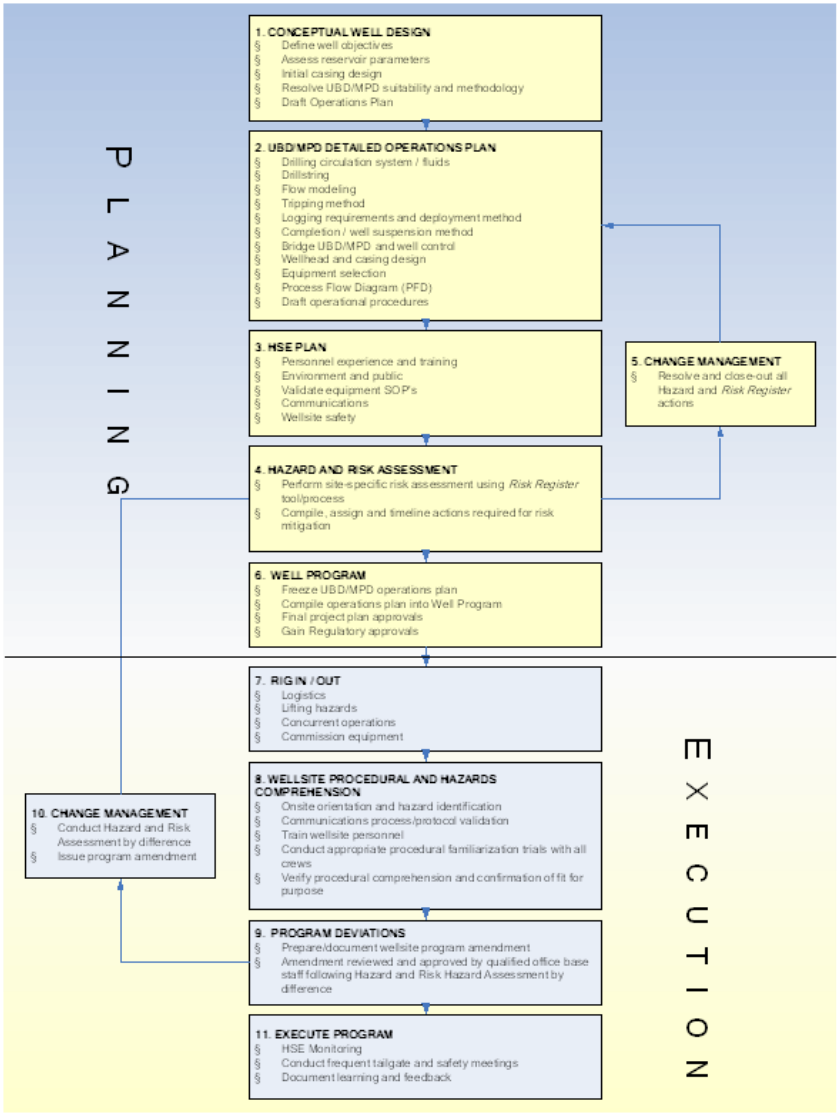
Table 9. Edition 4 Development Committee

Name	Company	Organization Represented
Ahmad Ahmad	Premium Oilfield Technologies	CAOEC
Justin Amyotte	Akita Drilling	CAOEC
Dallas Carol	DC Drilling	CAOEC
Duane Carol	DC Drilling	CAOEC
Tyler Cherry	CNRL	CAPP
Stacy Goertz	Frontier International	CAOEC
Philip Gunn	Beyond Energy	
Scott Hoekstra	Weatherford	CAOEC
Leroy Hollman	Veren	CAPP
Ali Koochi	ARC Resources	CAPP
Brent Kryzanowski	Bear Drilling	CAOEC
Kaila Lewis	Paramount Resources	CAPP
Leiro Medina	Beyond Energy	
Sandeep Randhawa	Cenovus	CAPP
Maria Retuta	CNRL	CAPP
Julius Sosa	Frontier International	CAOEC
Vino Thirukkumaran	PETRONAS Canada	CAPP

Appendix B: Project Management Process

The following figure illustrates a typical Project Management Process for planning and execution of UPB/MPD projects. Continuous improvement, in the form of lessons learned from previous jobs, should be incorporated into the process.

Figure 10. Project Management Process



Appendix C: Hazard and Risk Assessment Process

The IRP 22 Hazard and Risk Assessment Process is based on the IRP 22 Risk Register. The purpose of the Risk Register is as follows:

- To provide minimum expectations for conducting risk assessments for MPD/UBD operations.
- To highlight industry identified MPD/UBD hazards scenarios and associated risk severity.
- To provide risk control/mitigation options for consideration.
- To supplement existing organizational risk assessment tools and practices with industry-wide experience.
- To provide an effective means for regulatory conformance and inspection.

The IRP 22 Hazard and Risk Assessment Process is not intended to replace existing organizational risk assessment processes and associated risk analysis tools or registers. It should be considered a minimum starting point rather than a complete MPD/UBD risk analysis tool for specific organizations or operations.

A more in detailed risk analysis study (e.g., HAZOP or Bow Tie Study) should be initiated for circumstances where a high-risk hazard is identified and not listed in the Risk Register. This will help to ensure that the operation can be executed safely and that risks are reduced to as low as reasonably possible.

The IRP 22 Committee encourages organizations to share lessons learned and additions to the Risk Register using the feedback mechanisms provided by Energy Safety Canada for IRP 22. All submissions will be reviewed for inclusion in the Risk Register to facilitate future quantitative analysis of the hazards associated with RMD/MPD/UBD operations.

Risk Tolerance and Severity

Risk tolerance and severity rankings differ among organizations and even among individuals within organizations. The Risk Register is intended to bring about specific awareness and offer a MPD/UBD industry-wide risk severity ranking standard for

common and known hazard scenarios, along with industry recommended practices and considerations for control and mitigation.

Figure 11 identifies a risk tolerability framework. The colour coding indicates whether risks from an activity or process are “broadly acceptable” (Green), “tolerable” (Yellow) or “unacceptable” (Red). The colours are used to indicate industry risk tolerability in the Risk Register.

Figure 11. Risk Tolerability Framework



Broadly Acceptable Tolerable Unacceptable

In this context, “tolerable” does not mean “acceptable”. Tolerable refers to a willingness to accept a risk to secure certain benefits in the confidence that the risk is one that is worth taking and that can be properly controlled. It does not imply that the risk will be acceptable to everyone (i.e., that everyone would agree without reservation to take the risk or have it imposed on them).

For each known hazard scenario identified in the Risk Register a qualitative assessment was conducted by IRP 22 subject matter experts to determine risk level.

Any hazard scenarios identified that are not listed in Risk Register should use the Risk Severity Matrix (Figure 12), at minimum, to determine risk level during well planning.

Figure 12. Risk Severity Matrix

Probability				
	High	Y	R	R
	Medium	G	Y	R
	Low	G	Y	Y
		Low	Medium	High
		Consequence		

Probability: How likely the hazard is to occur during the operation

Consequence: The severity of the result if the hazard scenario is realized

The following suitable controls or mitigation actions are required for each defined hazard's risk severity level:

R	Engineering, procedures and training required
Y	Procedures and training required, should consider engineering
G	Training required, should consider engineering and procedures

IRP 22 supports good engineering design principles that aim to eliminate hazards over controlling hazards and controlling hazards over providing personal protective equipment.

Risk Register

The Risk Register is a downloadable spreadsheet that allows user customization for job and site-specific operations. The IRP 22 Risk Register is available for download on the IRP 22 page of the Energy Safety Canada website.

The Risk Register was compiled by a group of MPD/UBD experts. It is a living document that combines hazard scenarios known and experienced at the time of the initial writing of IRP 22 with updates from various reviews and industry input. It is not necessarily an exhaustive listing of all hazard scenarios. The Risk Register and related IRPs are recommended practices not prescriptive procedures. This IRP and the Risk Register are intended to share the recommended practices for the benefit of the entire MPD/UBD industry. The Risk Register applies the concept of "reasonably practicable" for control/mitigation of hazard scenarios.

While the primary focus of the Risk Register is Health, Safety and Environment risks, non-productive time is considered as well. In many cases HSE and NPT items are related. Designing a program that reduces the potential for NPT will typically result in the execution of a program with fewer HSE incidents.

Risk Register Spreadsheet

The risk register has several worksheets as explained in Table 10.

Table 10. Risk Register Worksheets

Sheet	Notes
Intro Sheet	Identifies column headings, risk severity and general notes about using the register. The general notes identify the last item number used in the current version of the spreadsheet.
Hazard Register MAIN	Identifies hazard scenarios specific to UBD, MPD, RMD or a combination of those. Excludes general drilling hazards (common to all operations). Those are found in Hazard Register GENERAL. Includes threats/consequences, the section in IRP 22 that addresses the hazard and additional considerations. Modify the entries as required by the organization, job or operation. See suggested usage information below.
Hazard Register GENERAL	Identifies hazard scenarios that are not specific to UBD, MPD, RMD or a combination of those. Includes threats/consequences, the section in IRP 22 that addresses the hazard and additional considerations. Modify the entries as required by the organization, job or operation. See suggested usage information below.
Operational Phases	The list of valid values for the operational phase column. Add any other phases required the organization or operation.
Relevance	The list of valid values for the relevance column (UBD, MPD, RMD or ALL)
Primary Responsible Party	The list of valid values for the Primary Responsible Party column. Add any other phases required for the organization or operation.
Primary Category	The list of valid values for the Primary Category column. Add any other categories required for the organization or operation.

Suggested Usage

The Risk Register items can be customized as required by the end user. In the default worksheets the hazard scenarios have been sorted numerically within operational phase.

> **Note:** Many hazard scenarios appear in multiple operational phases. They are not duplicate entries because the threats/consequences, severity, considerations and/or actions may be different.

The following are some tips for the most effective use of the Risk Register:

1. Set the “Applicable” column to Y if the scenario is applicable to the operation or N if it does not. This column can then be used to sort all of the non-relevant entries to the bottom. Consider the Relevance column (UBD, MPD, RMD or ALL) to determine if the scenario is applicable.
2. Use the options in the column headers to remove entries that don’t apply to the operation or sort the data differently. (For example, sorting by Primary Responsible Party can group items that need to be handled by the same party together for easier reviewing).
3. High risk scenarios are noted as red in both the “HSE” and “NPT” columns. Refer to the applicable section of the IRP (Required HSE Critical Controls/Safeguards column) for more mitigation information.
4. Customize the valid values for the operational phase, relevance, responsible party or primary category columns to allow for additional entries specific to the operation.
5. Review the threats and considerations and make any notes about actions or responses in the Actions column.

Refer to the Intro Sheet in the Risk Register for more notes about using the Risk Register.

Appendix D: Drilling Fluids

The following information is intended to support drilling fluid selection in the planning process (as per 22.4.5 Drilling/Produced Fluids).

Considerations for Drilling Fluid Design

Table 11. Considerations for Drilling Fluid Design

Consideration	Description
Formation Lithology	• Core and/or drill cuttings data • Log and geophysical data • Scanning Electron Microscope (SEM) and X-Ray diffraction data • Lab compatibility tests (Swelling test, shale reactivity, retained permeability) • Data from offset wells including drilling fluid log data • Prior drilling histories including overbalanced drilling information
Formation Fluids	• Reservoir fluids samples • Composition of all reservoir fluids (oil, gas, water) • Emulsion test results • MPD/UBD drilling fluids/formation fluid stability • Gas mixtures affecting explosion envelope • Formation Damage Test(s) results
Hole Cleaning	• Well bore geometry • Rate of Penetration (ROP) • Fluid cuttings carrying capacity • Potential lost return zones • Caliper (washout and/or ovality) • Frictional effects on ECD
Corrosion	• Effects on both surface and downhole equipment • Drilling gas/fluids (amount of dissolved oxygen) • Formation (CO_2 & H_2S) gas/fluid types • Salinity of drilling and formation fluids • Temperature & Pressure profile • Review corrosion control requirements • Estimated contact time effects • Elastomers compatibility
Down Hole Tools	• MPD/UBD method used • Data transmission effects • Hydraulics for running motors

Consideration	Description
	• Logging and/or coring requirements • Completion requirements considerations
Health and Safety	• Maximum exposure limitations of fluids and gas components • Equipment design specifications • Training • Local safety regulatory compliance (for personnel and equipment) • Qualitative risk assessment and analysis • Emergency response plan • Material transportation, storage and handling procedures
Environment and Disposal	• Compliance with regulation • Compliance with operator guidelines • Waste characterization profile • Evaluation of disposal options (for cuttings, produced fluids, drilling fluids, etc.)
Logistics	• Water • Oil • Diesel • Nitrogen • Natural gas • CO • CO_2 • Steam • Access • Spacing • Storage • Handling
Elastomer compatibility	• Aniline point analysis • Rubber composition • Fluid type (special attention for oil-based fluid) • Condensate production

Process for Drilling Fluid Selection

The following is a sample process for drilling fluid selection.

Step 1: Define the Objective

Define whether the purpose of drilling underbalanced is due to reservoir considerations or drilling operation considerations.

Reservoir considerations include the following:

- Reduction of skin damage in the target production zone

- Increased productivity index
- Increased recoverable reserves
- Increased production rate
- Production of reservoir fluids for sale while drilling

Major conditions for drilling fluid selection related to the reservoir considerations are as follows:

- The lowest and the highest pore pressure and depth of the target production zone.
- The type of formation and formation damage mechanism.
- The reservoir characteristics of the production zone.
- The borehole stability (geophysical/geomechanical).
- The potential type and anticipated rate of production.

Drilling operation considerations include the following:

- Ability to drill through transition zones.
- Increased ROP.
- Reduction of lost circulation incidents.
- Reduction of drilling downtime.

Major conditions for drilling fluid selection related to the operational considerations are as follows:

- Drilling fluid/gas and cuttings that will be brought to surface.
- Drilling fluid handling and solids processing equipment available on site.
- Nitrogen, water formation, oil formation, gas/foam handling and separation equipment requirements.
- Emulsion handling and separation issues and requirements.
- Surface equipment selection should consider fluid handling capacity.
- Effect of erosion on surface equipment.
- Impact of returned fluids on elastomers (RCD element selection).
- Hydrocarbon separation, storage and transmission requirements.

Step 2: Gather data

The following data is required for drilling fluid selection.

Table 12. Fluid Selection Data Requirements

Type	Description
Reservoir	• Formation type (sand, limestone, clays, etc.) • Pore pressure • Temperature • Formation bearing fluids (water, oil and gas) and characteristics (composition water, gas, PVT analysis (pressure, volume, temperature)) • Geophysical/Geomechanical information • Permeability • Porosity
Well Geometry	• Directional characteristics • Hole size • Proposed casing program
Offset History Logs	• Drilling fluid logs • Production history • Well test data • Seismic data • Drilling reports

Step 3: Establish the required equivalent circulating density (ECD)

ECD values should be the maximum required for the pore pressure and minimum required for borehole stability.

This interval can be determined by analyzing the following:

- Bottomhole pressure information
    - Fluid modeling
    - Drawdown pressure vs production rate
    - Pressure transient testing and analysis
- Geomechanical information
    - Empirical models
    - Lab tests for cores
    - Sonic log data
- Reservoir fluid type (i.e., the effect of reservoir inflow on ECD
- PVT curves

Step 4: Classify the well based on ECD and IADC

Once the well's objectives are defined and the ECD interval is established the well can be classified based on IADC Well Classifications (see Well Classifications in the Glossary).

Table 13. IADC Well and ECD Classification[6]

Classification	Fluid	ECD Range (kg/m^3)
Gas	Air, Nitrogen, Natural Gas	1.2 – 12
Mist (less than 2.5% liquid content)	Mist	1.2 – 12
Foam (55% - 97.5% gas content)	Dry	12 – 36
	Wet	36 – 422
Gasified Liquid		422 – 831
Liquid	Oil-based	904 – 2289
	Emulsion	904 – 2048
	Water-based	1000 – 2289

Step 5: Choose the required equipment

Once the drilling fluid ECD interval is determined the required equipment can be selected. Due to the complexity and sensitivity of the equipment, IADC equipment classification should be used in the selection process.

Table 14. IADC Equipment Classifications

Fluid Group	Fluid	Equipment Suggestions
Gas Drilling	Air	Compressors, boosters, mist/foamer pump, rotating head/diverter, flare/flame, drill string floats, separation equipment, chokes, manifolds
	Nitrogen	Cryogen tanks & heaters – OR – membrane nitrogen generators, boosters, mist/foamer pump, rotating head/diverter, flare/flame, drill string floats, separation equipment, chokes, manifolds
	Natural Gas	Pipeline / gas source, compressors, boosters, mist/foamer pump, rotating head/diverter, flare/flame, drill string floats, separation equipment, chokes, manifolds

[6] IADC UBO Committee. Fluid Selection for Underbalanced Drilling Operations. 2001.

Fluid Group	Fluid	Equipment Suggestions
Mist Drilling	Mist	Source of gas, small injection pump, compressors, boosters, mist/foamer pump, rotating head/diverter, flare/flame, drill string floats, separation equipment, chokes, manifolds
Foam Drilling	Dry Foam	Source of gas, compressors, boosters, foam generator, rotating head/diverter, flare/flame, special metering equipment, defoaming tank and pump, drill string floats, separation equipment, chokes, manifolds
Gasified Liquid Drilling	Gasified Liquid	Gas/liquid separator, compressors, boosters, RMD/MPD/UBD flare line, rotating head/diverter, flare/flame, drill string floats, separation equipment, chokes, manifolds
Liquid Drilling	Oil Based	Rotating head/diverter, drill string floats, cuttings disposal, separation equipment, chokes, manifolds
	Emulsion	Rotating head/diverter, drill string floats, cuttings disposal, separation equipment, chokes, manifolds
	Water Based	Rotating head/diverter, drill string floats, separation equipment, chokes, manifolds

Some additional equipment considerations are as follows:

- A snubbing unit, a coiled tubing unit, casing drilling, parasitic strings and closed loop systems may be required.
- H_2S production requires special considerations (see IRP 06: Critical Sour Underbalanced Drilling for more information).
- Gas and H_2S monitoring systems, confined space, explosion-proof electrical equipment, electrical bonding/grounding and wind socks should be considered.
- Depending on fluids used and production, 2-phase or 3-phase separators (vertical or horizontal) may be required.
- Additional lighting, firefighting equipment and power generation may be required.
- Special data acquisition systems should be considered.
- A HAZOP risk assessment is recommended if crude oil is being considered as the MPD/UBD fluid.

Appendix E: Erosion and Corrosion

Corrosion is the destruction of metal by chemical or electrochemical means. Potential agents for initiating corrosion include carbon dioxide, hydrogen sulphide, chlorides and oxygen. All of these agents can be introduced into the circulating system during wellbore or surface circulation of the circulating media. Corrosion could result in pitting, embrittlement, sulphide stress cracking or black sulphide coating. Factors that affect corrosion rates include the oil/water ratio, conductivity of the electrolyte, pH, temperature, pressure, velocity and dissolved gases.

Oil/Water Ratio

As a general rule, the more water present in the system, the greater the tendency for corrosion. Corrosion should be anticipated in any system if the water content exceeds 25%.

Assuming no inhibitors are used, corrosion will be more severe

- in mist than in air,
- in foam than in mist and
- in aerated fluids than in foam.

Conductivity of Electrolytes

The more conductive the electrolyte is, the greater the tendency for corrosion. Conductivity is increased with brine concentration so high concentration brine will lead to destabilization of the foam system which increases the free water percentage. Additional free water will trigger the acceleration of the corrosion rate if not properly inhibited.

pH

The corrosion rate increases as pH value decreases. However, very high pH values can be extremely corrosive as well. With a pH between 9 and 11 the corrosion rate is

minimal but scaling potential is increased. A pH above 9 to 9.5 will accelerate the corrosion rate of aluminium drill pipe.

Temperature

Corrosion rate increases as temperature increases. It can be estimated as doubling for every 10°C increase in temperature. This affects the stability of the foam systems allowing increased free water into the system.

Pressure

As pressure increases more gases may be dissolved into a fluid. This increases the fluid corrosiveness if acid gases are present.

Velocity

The corrosion rate increases as fluid velocity increases. In MPD/UBD systems the increased velocity of fluids containing drilled solids will improve the surface cleaning (i.e., a scouring effect). This is beneficial when scaling is a problem. The removal of the scale deposits will reduce the under deposit pitting corrosion.

Dissolved gases

The existence of oxygen, carbon dioxide and/or hydrogen sulphide in a fluid (especially water) can dramatically increase the corrosiveness of the fluid.

Consider the following:

- Oxygen is a major component in UBD operations using compressed air.
- Carbon Dioxide is not as much of a problem as dissolved oxygen but can become a real concern. CO2 as gas does not create corrosion problems but it is readily soluble in water which generates carbonic acid. This pushes the pH Value down and drastically increases corrosion.
- Hydrogen sulphide by its nature has significant safety and corrosion concerns. H_2S is readily soluble in water and, at any concentration, generates major corrosion concerns. The corrosion mechanisms induced by H_2S are described in IRP 01: Critical Sour Drilling, IRP 06: Critical Sour Underbalanced Drilling and NACE MR0175/ISO 15156 Materials for use in H_2S-containing environments in Oil and Gas Production.

Collateral Corrosion Triggers

Solids

Any solid deposited on a metal surface can cause increased corrosion under the deposit due to differential concentrated corrosion cell action. This phenomenon causes pitting type corrosion under the deposit. In the presence of dissolved oxygen this pitting can become severe without a proper corrosion inhibition. One of the most important considerations in MPD/UBD operations is the water contained in the drilling fluid (if used). A fluid that has a negative scale potential, is compatible with formation fluids, does not contain suspended solids or H_2S and is low in dissolved Iron (less than 10 ppm) will alleviate the potential solids induced corrosion.

The following table lists typical solids encountered in MPD/UBD operations.

Table 15. Typical Solids Encountered in UBD Operations

Solid	Chemical Formula
Calcium Carbonate	$CaCO_3$
Calcium Sulfate	$CaSO_4$
Barium Sulfate	$BaSO_4$
Iron Carbonate	$FeCO_3$
Iron Hyrdoxide	$Fe(OH)_3$
Iron Sulphide	FeS
Iron Oxide	Fe_2O_3

Bacteria

The existence of bacteria can accelerate corrosion. The rate of corrosion is dependent upon the type of bacteria, anaerobic or aerobic, and the dynamic of the drilling system. The most common source of bacteria is polluted or reused water in the drilling fluid.

Mechanical Stress

The corrosion rate can be accelerated by residual or externally applied stress.

Dissimilar metals

Galvanic corrosion occurs when two or more metals of different metallurgy are connected. This is due of the difference between electrical potential of the metals (which

act as cathode and anode electrodes). The higher the electromotive service potential the faster the metal corrodes.

The following table shows the electromotive series potential of several metals compared to hydrogen.

Table 16. Electromotive Service Potential of Metals Compared to Hydrogen

Metal	Electromotive Service Potential
Potassium	+ 2.925
Barium	+2.9
Calcium	+2.87
Sodium	+2.714
Magnesium	+2.37
Aluminum	+1.66
Manganese	+1.18
Zinc	+0.763
Chromium	+0.74
Iron	+0.44
Nickel	+0.25
Tin	+0.136
Lead	+0.126
Hydrogen	0
Copper	-0.337
Mercury	- 0.789
Silver	-0.799
Platinum	-1.2
Gold	-1.5

Monitoring

Corrosion

The following should be considered when dealing with corrosion:

- A corrosion monitoring program should be in place and appropriate for the corrosion risks of the fluid being used.
- When drilling under corrosive conditions the circulating media should be monitored to indications of corrosion and to determine the effectiveness of corrosion control measures.

- Corrosion indicators (e.g., rings, coupons or suitable alternatives) are to be installed at appropriate/practical circulating stream locations (e.g., surface piping, drill pipe, BHA, etc.) to measure corrosion rates if operating under potentially corrosive conditions.
- Corrosion indicators are to be regularly inspected to establish corrosion rates.
- Consideration should be given to precautionary measures (such as regular tripping to inspect the drill string/BHA) to establish the severity of downhole corrosive conditions when drilling in an area where the corrosive environment is not thoroughly understood.

Oxygen

The oxygen content of any injection stream which has the potential to introduce oxygen into the circulating stream should be monitored to ensure that explosive limits are never reached during MPD/UBD operations.

Flow Rate

Circulation parameters should be monitored to ensure the system capability is not exceeded. Parameters that require monitoring include, but are not limited to, the following:

- Gas and liquid production rates
- Injection pressures
- Wellhead annular pressure
- Bottomhole annular pressure
- Surface volumes
- H_2S

Extensive detail regarding the monitoring of H_2S and measures to mitigate the hazards of H_2S can be found in IRP 01: Critical Sour Drilling, IRP 06: Critical Sour Underbalanced Drilling, AER Directive 71: Emergency Preparedness and Response Requirements for the Petroleum Industry, NACE MR0175/ISO 15156 and in OH&S regulations. These resources should be referenced for H_2S monitoring of all standard, UBD or MPD operations.

Corrosion Inhibitors

The following table describes the two types of corrosion inhibitors.

Table 17. Corrosion Inhibitors

Inhibitor	Notes
Cationic Inhibitors	• Produce a film surface on the metal. • This film is disrupts the circuit of the corrosion cell via the existing electrolyte. • This kind of inhibitor generically named as “filming amines”. • Amine derivatives such as ethoxylated fatty amines, quaternary ammonium chlorides and amine salts are effective inhibitors in drilling fluid systems. • These inhibitors are cationic materials and are not compatible with foaming agents.
Anionic Inhibitors	• These inhibitors are the most effective in MPD/UBD operations. • They are compatible with foaming agents and they perform well in the presence of the dissolved oxygen. • Organophosphate esters should have good thermic stability (up to 300 °F), be biodegradable and have a low order of toxicity.

Appendix F: Process Flow Diagrams

The Process Flow Diagrams in this appendix have been identified to help control risks and achieve industry standardization for the majority of applications anticipated within the Western Canadian Sedimentary Basin (as per 22.6 Process Flow Diagrams). The six diagrams are as follows:

- RMD System
- Sweet MPD System
- Sour MPD System
- Sweet UBD System
- Sour UBD System
- Rig Choke tie-in to the RMD/MPD Surface Separation Equipment

These diagrams are available for download from the IRP 22 page of the Energy Safety Canada website.

Figure 13. RMD System

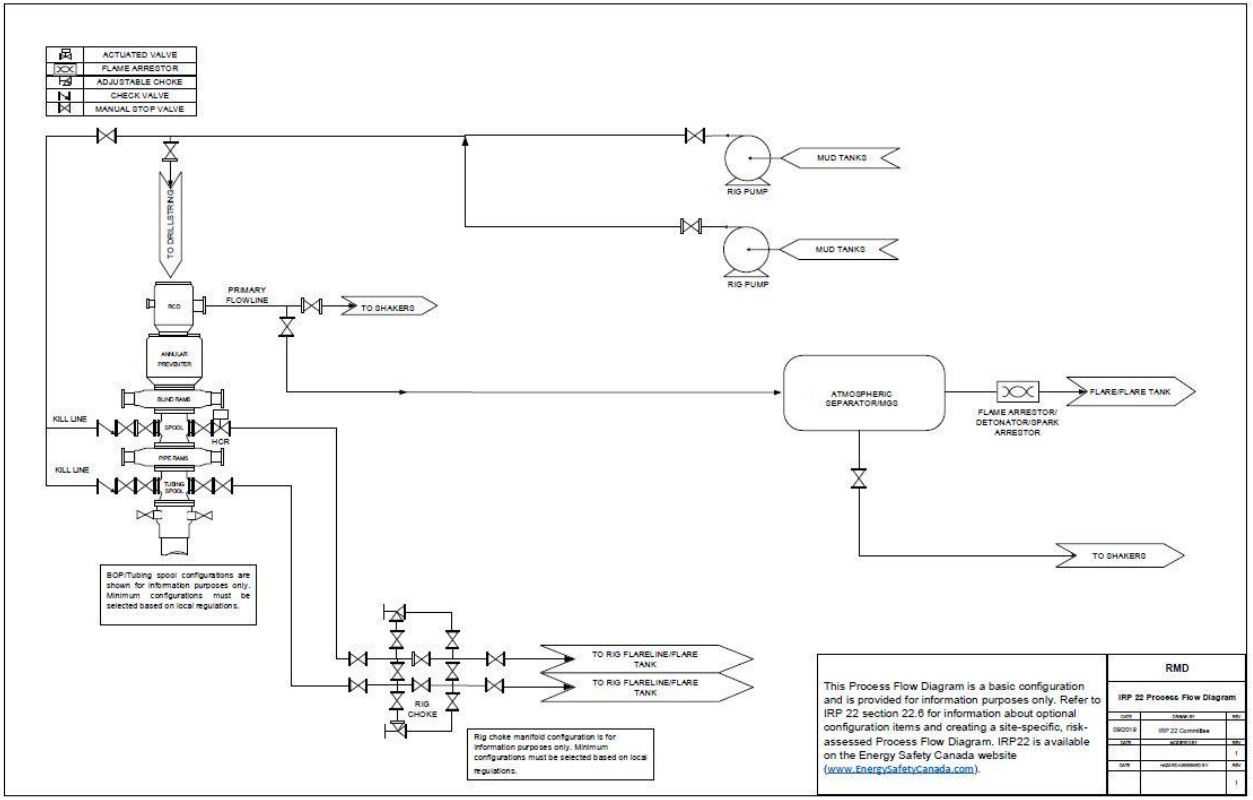


Figure 14. Sweet MPD System

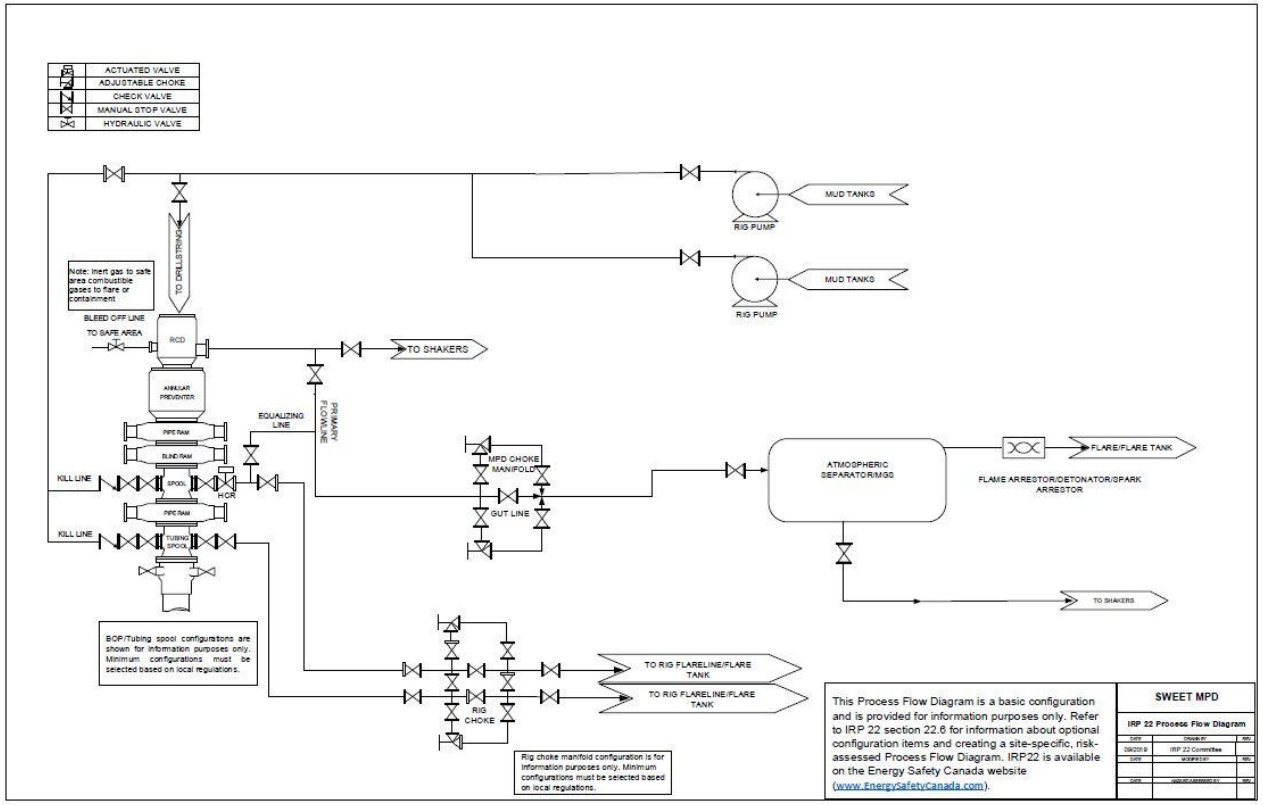


Figure 15. Sour MPD System

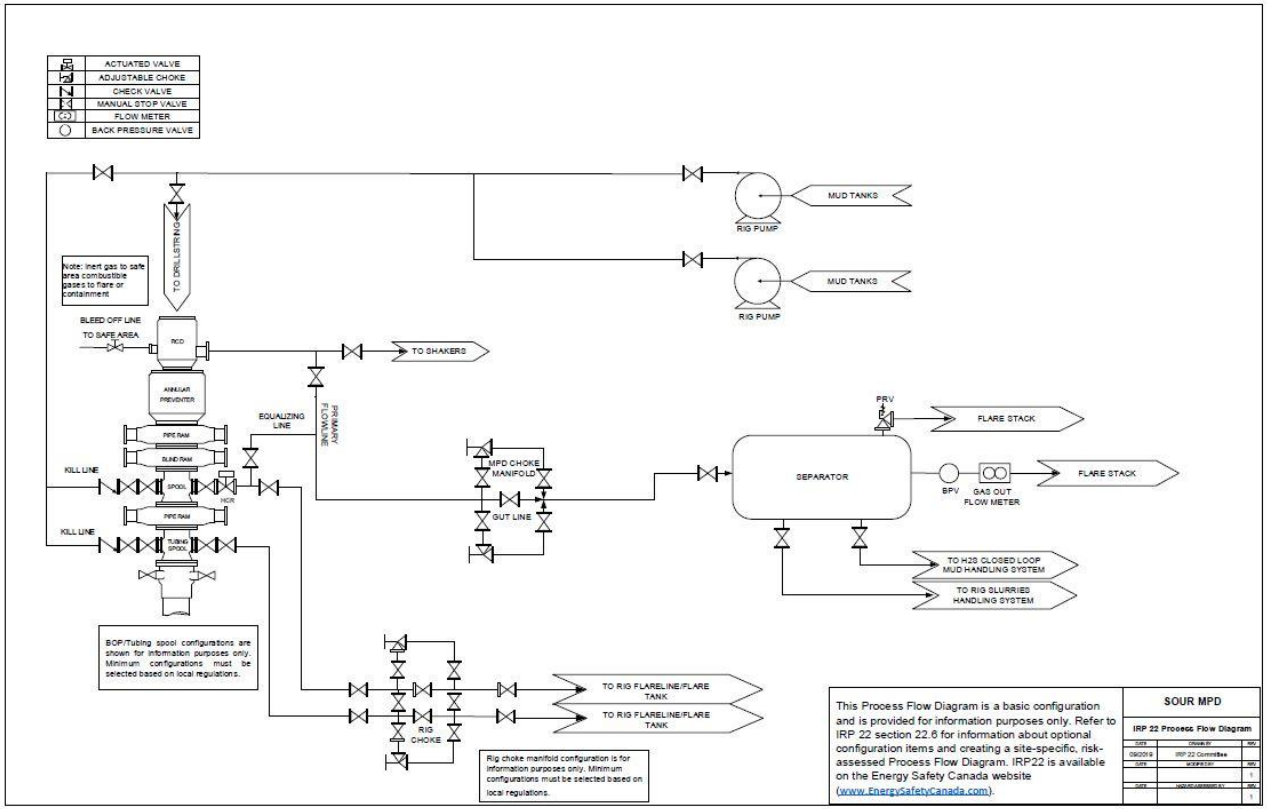


Figure 16. Sweet UBD System

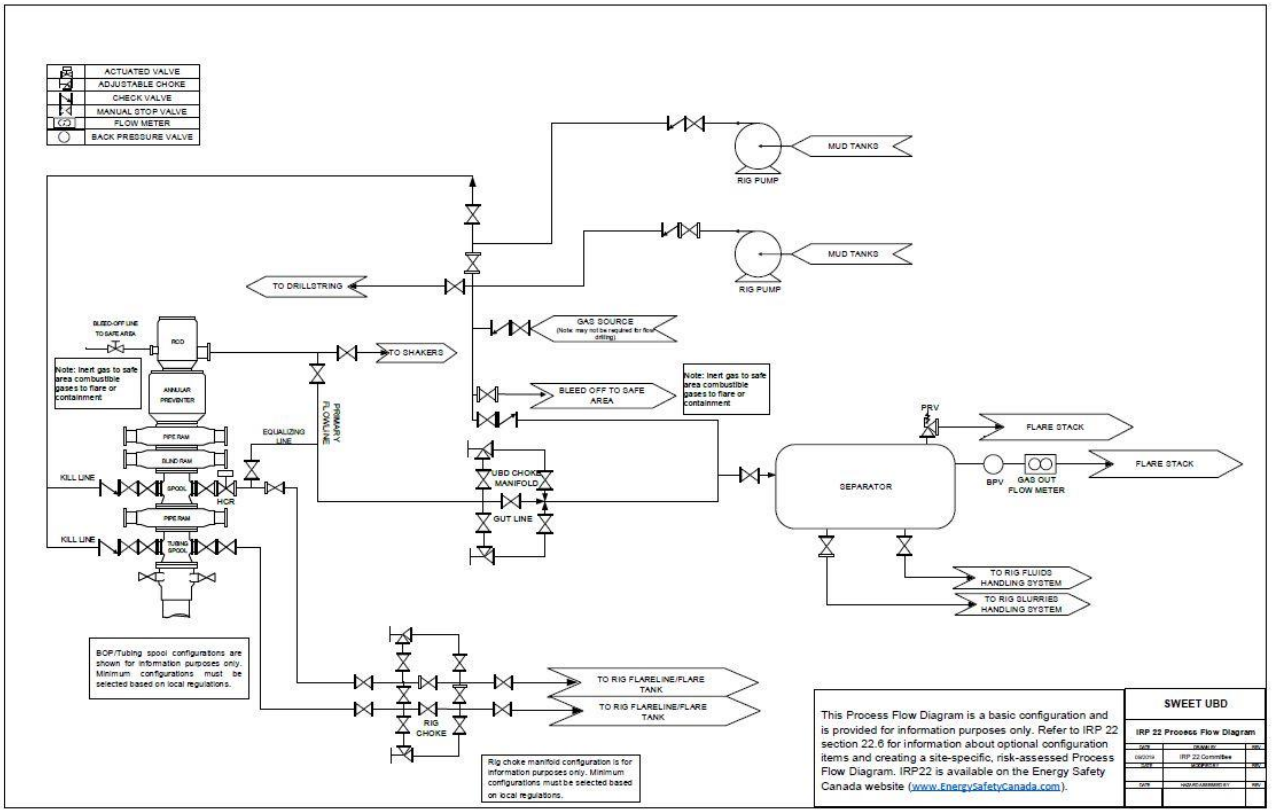


Figure 17. Sour UBD System

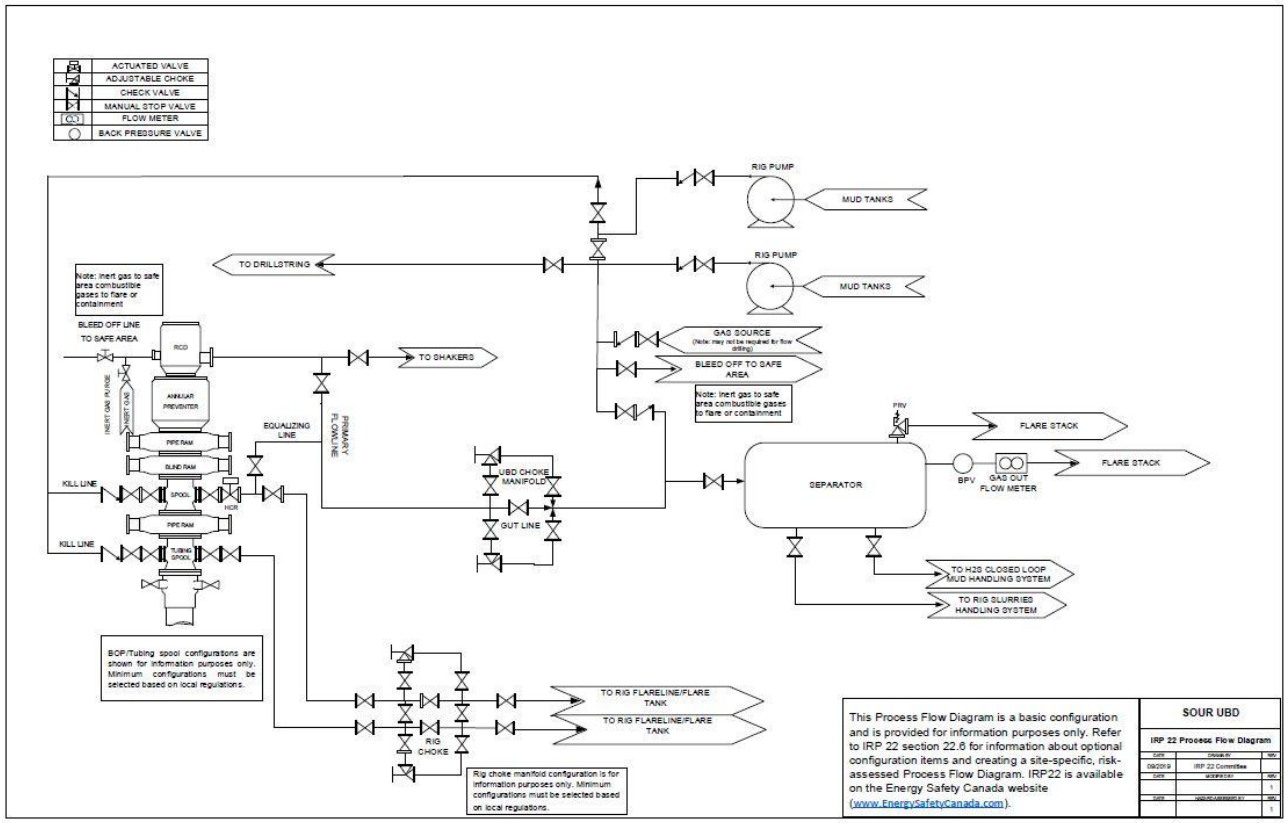
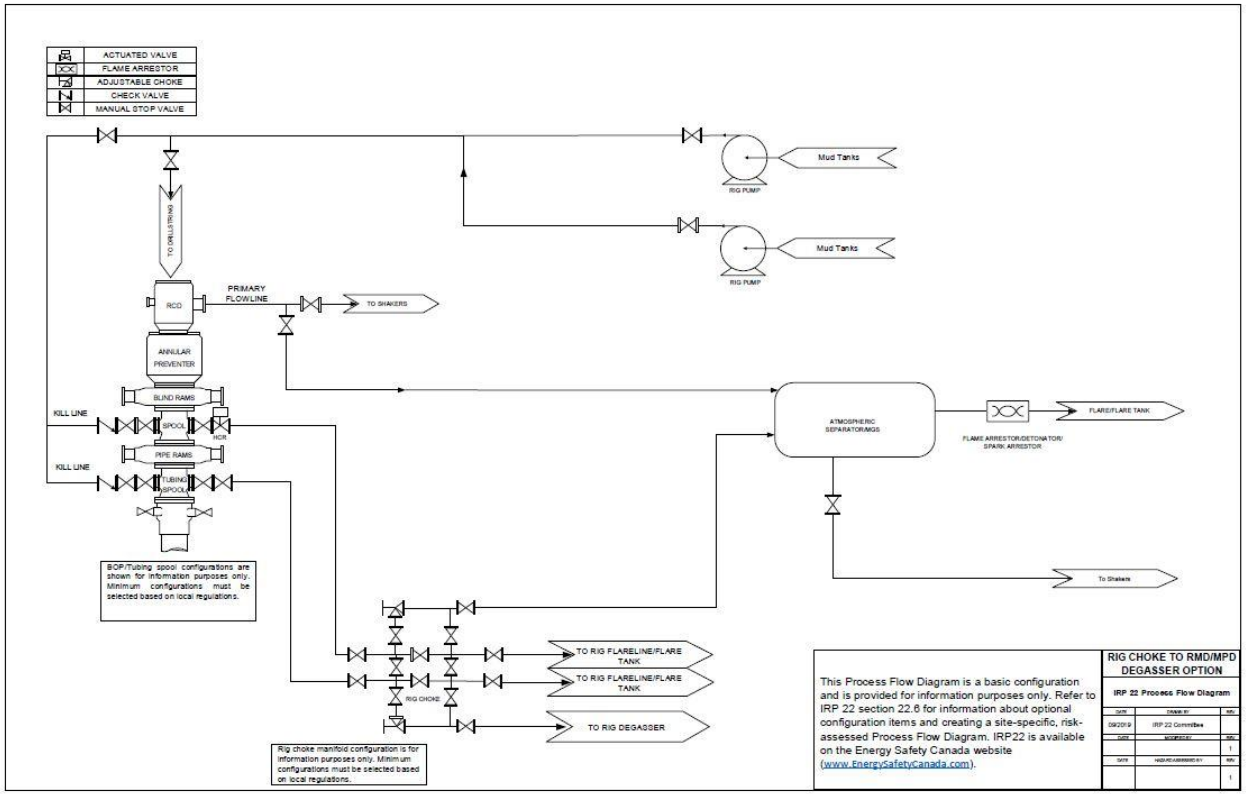


Figure 18. Rig Choke Tie-In to RMD/MPD Surface Separation Equipment



Appendix G: Recommended Training Topics

The topics and activities listed in this section identify the minimum learning objectives required for personnel involved in the activities. It is the responsibility of the operator and/or service provider to determine which role (e.g., wellsite supervisor, rig manager, underbalanced engineer, etc.) will be responsible for each of the activities and which personnel requires the training.

Introduction to MPD/UBD

Table 18. Introduction to MPD/UBD

Training Topics	Learning Objectives
Definitions of conventional, RMD, underbalanced drilling and managed pressure drilling	• Define conventional drilling, MPD, UBD and emphasize the difference between them
General Theory of the MPD	• Understanding managing BHP from the return (SBP) and/or injection (injection rates) side .
MPD Classifications	• Understanding the differences between all MPD/UBD variants: • MPD: CBHP, PMCD, DG, CF, multi-phase (Low Head). • UBD: UBD, Flow drilling, etc.

Well Control in Conventional Drilling

Table 19. Well Control in Conventional Drilling

Training Topics	Learning Objectives
Valid Blowout Prevention Certificate	• BOP Stack • HSE • Barrier verification • Understand that the secondary well control barrier is the same as in conventional drilling
Well Control Certification	• Control of well at all times • HSE • Early kick detection • Overbalanced at all times • Controlling hydrocarbon influx

Well Control in MPD/UBD

Table 20. Well Control in MPD

Training Topics	Learning Objectives
Valid Blowout Prevention Certificate	• BOP Stack • HSE • Barrier verification • Secondary barrier is the same
Well Control Certification	• Control of well at all times • HSE • Early kick detection • Overbalanced at all times • Controlling hydrocarbon influx
Kick Detection Tools in MPD	• Flow out measurement • Annular Discharge Pressure (or Backpressure) • Choke Position • Standpipe Pressure • PVT
Handling Influx	• Kick Modelling • Kick Circulation
MPD/UBD Well Operational/Flow Matrix	• Describe the limits of the operating/flow matrix and course of actions • Describe limitations of the Operating Pressure Window/Operating Envelope • Explain EMW, ECD dynamic vs static, etc.

MPD/UBD Rig Up/Rig Integration

Table 21. MPD Rig Up/Rig Integration

Training Topics	Learning Objectives
RCD	• Purpose and functionality of RCD • Static and dynamic rating of RCD • Identify factors affecting seal life
Choke Manifold	• Evaluate the specification (e.g. pressure rating, auto, manual, actuator etc) • Identify the pressure and flow rate limitations • Identify the failure modes (e.g. plugging, washout, etc.) and mitigations. • Pressure relief and bypass strategy.
Return Flow Meter	• Evaluate the specification and identify the limitations. • Identify the failure modes and mitigations.
Pressure Relief Valves and Drill String Floats.	• Selection and placement of PRVs and drill string floats.

Training Topics	Learning Objectives
Instrumentation and Automation	• Identify the pressure sensors and gauges used in MPD. • Identify the limiting factors for all the sensors. • Cause &Effect analysis for potential failure mechanism of automated systems.
Process Flow Diagram	• Understanding PFD, HP Lines, LP Lines, Choke manifold, NRV lineup
Separation Equipment	• Identifying main components of a separator • Criteria for using separator • Trip gas and connection gas vs kick

MPD Tripping

Table 22. MPD Tripping

Training Topics	Learning Objectives
Surge Effect	• Understanding surge effect relation with BHP during tripping into the hole and potential losses
Swab Effect	• Understanding swab effect relation with BHP during tripping out the hole and potential kick
MPD Mud Rollover/Displacement	• Mud Cap placement • Dynamic fluid displacement while keeping BHP constant

MPD/UBD HSE

Table 23. MPD HSE

Training Topics	Learning Objectives
HAZID/HAZOP/MOC/Risk Assessment	• Understanding HAZID, HAZOP and MOC
Bridging Documents and HSE Planning	• Understanding use of bridging documents • Describe the importance of good communication between all involved parties •
IRP Documentation	• Understanding IRP documentation and benefits of using it
Procedures	• Operational procedures (e.g., connections, tripping, changing out RCD bearings, etc.)

It is recommended that MPD training include applicable regulatory requirements for the jurisdiction in which the operation is conducted.

Appendix H: RMD Equipment Checklist

IRP 22 defines RMD as “A drilling activity where hydrostatic mud weight could be less than pore pressure of the formation but the well is not believed to be capable of flow to surface. The intention is to handle/respond to nuisance gas at surface with appropriate equipment.”.

Note: RMD configurations do NOT include a choke. If a choke is added then the operation becomes MPD/UBD and requires MPD/UBD equipment and on-site personnel competent to use the equipment.

For purposes of IRP 22, nuisance gas could be one or more of the following: trip gas, drill gas, bottoms-up gas or connection gas.

Note: A continuous flare may indicate there is more than nuisance gas being dealt with. At this point it is necessary to review job parameters and equipment limitations to confirm that RMD is still appropriate (see 22.8.5.1 RMD Operations Matrix).

Refer to 22.1.1 Definitions for a more detailed description of the expectations of RMD.

The RMD Checklist outlines all of the topics that need to be discussed between a service provider and operator/drilling contractor when RMD equipment is provided. A review of the topics in the checklist will help ensure all personnel involved with the equipment have the necessary knowledge to operate the equipment, understand operational limits and know what to do if operations don’t go as planned. The checklist is to be completed for each new well. The completed RMD checklist should be filed with the job documentation and be available to all required personnel.

Table 24. Sections of the RMD Checklist

Section	Information
Well Information	The parties involved in the operation, well location (and license), contact information for the equipment provider.
Equipment	Lists the equipment for the operation, operating limits, pressure ratings, inspection requirements, maintenance requirements.
Procedures and Operational Documentation	Lists the information the equipment provider is expected to provide and the drilling contractor is expected to discuss at the pre-drillout meeting. **Note:** IRP 22 provides templates for the PFD and operations matrix but these must be customized for each operation. The equipment installation

Section	Information
	should be inspected to ensure it matches the PFD. All personnel involved in the operation should understand the operations matrix and their role during well control events once the indicators in the operations matrix have been observed.
Signoff	The personnel who need to understand the equipment requirements and their operational use and confirm that all sections of the RMD Checklist have been covered.
Comments	Any comments added during review.

A sample of the RMD Checklist is shown in Figure 19. A printable version can be found on the Energy Safety Canada website (www.energysafetycanada.com) on the IRP 22 page.

Figure 19. RMD Checklist

RMD Equipment Checklist

Well Information			
Operator:		Drilling Contractor:	
Location:		License:	
Equipment Provider:		Provider Contact:	Ph:

Equipment Information Provided and Reviewed[1]				
	Equipment Provided	**Documentation Provided**	**Inspection Requirements**	**Maintenance Requirements**
RCD	Y / N	Y / N	Y / N	Y / N
RCD Spare Elements	Y / N	Y / N	Y / N	Y / N
Degasser	Y / N	Y / N	Y / N	Y / N
Flowlines	Y / N	Y / N	Y / N	Y / N
Flow Meter	Y / N	Y / N	Y / N	Y / N
Other:				
	Y / N	Y / N	Y / N	Y / N
	Y / N	Y / N	Y / N	Y / N

Procedures and Operational Documentation	**Provided**	**Reviewed/ Verified**
Process Flow Diagram[2]	Y / N	Y / N
Operations Matrix[2]	Y / N	Y / N
SOPs for Equipment	Y / N	Y / N
JSAs for Equipment	Y / N	Y / N
Equipment Manuals	Y / N	Y / N
Pre-Drillout Meeting/Handover	Y / N	Y / N
Other:		
	Y / N	Y / N

Signoff[3]	**Name**	**Signature**	**Date**
Licensee Representative			
Rig Manager			
Driller			
Driller (Alternate)			
Service Provider			

Comments

[1] Refer to documentation provided by provider for ratings, inspection, maintenance and equipment specifications.
[2] Available on the IRP 22 page of the Energy Safety Canada website (www.energysafetycanada.com).
[3] Signoff indicates the above information has been provided and has been reviewed with the equipment provider.

Appendix I: MPD Equipment Checklist

Refer to 22.1.1 Defining the Terms for a more detailed description of the expectations of MPD.

The MPD Equipment Checklist outlines all of the topics – equipment and procedural – that need to be discussed when MPD equipment is to be used for an operation. This includes rental MPD equipment. The equipment checklist indicates equipment items and checks. The procedures checklist outlines the procedural documentation that should be in place.

Note: It is the responsibility of the user/renter to ensure the procedural calculations are documented and relevant discussions take place. This information does not come from the equipment provider.

A review of the topics in the checklists will help ensure all personnel involved with the equipment have the necessary knowledge to operate the equipment, understand operational limits and know what to do if operations don't go as planned. The checklists are to be completed for each operation or rental. The completed MPD Equipment checklist should be filed with the job documentation and be available to all required personnel.

Table 25. Sections of the MPD Equipment Checklist – Equipment

Section	Information
Well Information	The parties involved in the operation, well location (and license), contact information for the equipment provider.
Equipment	Lists the equipment for the operation, operating limits, pressure ratings, inspection requirements, maintenance requirements.
Signoff	The personnel who need to understand the equipment requirements and their operational use and confirm that all sections of the MPD Equipment Rental Checklist have been covered.
Comments	Any comments added during review.

Table 26. Sections of the MPD Equipment Checklist – Procedures

Section	Information
Well Information	The parties involved in the operation, well location (and license), contact information for the equipment provider.
Procedures and Equipment Documentation	Procedures and Operational Documentation Lists the information the equipment renter is expected to provide and the drilling contractor is expected to discuss at the pre-drillout meeting. **Note:** IRP 22 provides templates for the PFD and operations matrix but these must be customized for each operation. The equipment installation should be inspected to ensure it matches the PFD. All personnel involved in the operation should understand the operations matrix and their role during well control events once the indicators in the operations matrix have been observed.
Signoff	The personnel who need to understand the equipment requirements and their operational use and confirm that all sections of the MPD Equipment Rental Checklist have been covered.
Comments	Any comments added during review.

A sample of the MPD Equipment Rental Checklist is shown in Figure 20. A printable version can be found on the IRP 22 page of the Energy Safety Canada website.

Figure 20. MPD Equipment Checklist

MPD Equipment Checklist - Equipment

Well Information				
Operator:		Drilling Contractor:		
Location:		License:		
Equipment Provider:		Provider Contact:	Ph:	

Equipment Information Provided and Reviewed[1]				
	Equipment Provided	Documentation Provided	Inspection Requirements	Maintenance Requirements
RCD	Y / N	Y / N	Y / N	Y / N
RCD Spare Elements	Y / N	Y / N	Y / N	Y / N
Degasser	Y / N	Y / N	Y / N	Y / N
Flowlines	Y / N	Y / N	Y / N	Y / N
Flow Meter	Y / N	Y / N	Y / N	Y / N
MPD Choke	Y / N	Y / N	Y / N	Y / N
Other:				
	Y / N	Y / N	Y / N	Y / N
	Y / N	Y / N	Y / N	Y / N

Equipment Documentation	Provided	Reviewed/ Verified
SOPs for Equipment	Y / N	Y / N
JSAs for Equipment	Y / N	Y / N
Equipment Manuals	Y / N	Y / N
Other:		
	Y / N	Y / N
	Y / N	Y / N

Signoff[2]	Name	Signature	Date
Operator Representative			
Rig Manager			
Driller			
Driller (Alternate)			
Equipment Provider			

Comments

[1] Refer to documentation provided by provider for ratings, inspection, maintenance and equipment specifications.
[2] Signoff indicates the above information has been provided and has been reviewed with the equipment provider.

MPD Equipment Checklist - Procedures

Procedural Documentation Provided and Reviewed	Reviewed/ Verified
Process Flow Diagram[3]	Y / N
Operations Matrix[3]	Y / N
Pre-Drillout Meeting/Handover	Y / N
Other:	
	Y / N
	Y / N

Signoff[4]	Name	Signature	Date
Operator Representative			
Rig Manager			
Driller			
Driller (Alternate)			

Comments

[3] Sample available on the IRP 22 page of the Energy Safety Canada website (www.energysafetycanada.com).
[4] Signoff indicates the above information has been provided and has been reviewed with the equipment provider.

Appendix J: Glossary

The following acronyms and definitions are used in the IRP 22.

AAAQO Alberta Ambient Air Quality Objectives

AER Alberta Energy Regulator (Formerly ERCB)

Air Drilling Air drilling is a performance drilling technique that primarily uses air to circulate and minimize bottomhole pressure while maximizing the rate of penetration. Air drilling is normally used through wellbore sections that do not contain hydrocarbons.

ALARA As Low As Reasonably Achievable. ALARA is a risk management principle under which exposure to a hazard or substance is reduced to a level as low as reasonably achievable through the application of appropriate control measures.

ALARP As Low As Reasonably Practicable. ALARP is a risk management principle under which risks are reduced to a level where the effort, time and cost of implementing further control measures would be grossly disproportionate to the additional risk reduction achieved.

AOF Absolute Open Flow

Application Category The following table outlines application category information as per IADC.

Table 27. IADC Application Categories

Category	Description
Category A	Managed Pressure Drilling (MPD). Drilling with returns to surface using an equivalent mud weight that is maintained at or above the open-hole pore pressure.
Category B	Underbalanced Operations (UBD). Performing operations with returns to surface using an equivalent mud weight that is maintained below the open-hole pore pressure.
Category C	Mud Cap Drilling. Drilling with a variable length annular fluid column which is maintained above a formation that is taking injected fluid and drilled cuttings without returns to surface.

API American Petroleum Institute

Atmospheric flow back tank An open tank which serves as the terminus of an air-drilling flare system. The tank is designed to permit release of any contained gas in

annular returns and contain returned drilled solids. It is designed to prevent pressure build-up in the flare piping system.

BHA Bottomhole Assembly

BHCP Bottomhole Circulating Pressure

BHECD Bottomhole Equivalent Circulating Density

BOP Blowout Preventer

Breakdown Pressure The pressure at which the rock matrix of an exposed formation fractures and allows fluid to be injected. The breakdown pressure is established before determining reservoir treatment parameters. Hydraulic fracturing operations are conducted above the breakdown pressure, while matrix stimulation treatments are performed with the treatment pressure safely below the breakdown pressure. (Source: SLB Oilfield Glossary).

Breakout Pressure The pressure at which breakouts occur. Breakouts are indentations in the wellbore.

BPV Backpressure Valve

CAPP Canadian Association of Petroleum Producers

CO Carbon Monoxide

CO_2 Carbon dioxide

Corrosion The destruction of metal by chemical or electromechanical means.

Closed Circulating System A closed circulating system is a handling system in which any re-circulated fluids are contained and/or not exposed to the atmosphere at any point. All solids and fluids handling at surface is via closed tanks that have appropriately designed pressure maintenance and venting/flaring systems. (In this instance, venting refers to tank vapours that have been scrubbed of H_2S.) In particular, closed mud pump suction tanks need to accommodate significant change in liquid volumes (e.g., regulated positive pressure maintenance system).

DACC Drilling and Completions Committee

DPPT Dynamic Pore Pressure Test

Drilling Fluid System The following table outlines drilling fluid system information as per IADC.

Table 28. IADC Drilling Fluid Systems

System	Description
Gas	Gas as the fluid medium. No liquid intentionally added.
Mist	Fluid medium with liquid entrained in a continuous gaseous phase. Typical mist systems have less than 2.5% liquid content.
Foam	Two-phase fluid medium with a continuous liquid phase generated from the addition of liquid, surfactant, and gas. Typical foams range from 55% to 97.5% gas.
Gasified Liquid	Fluid medium with a gas entrained in a liquid phase.
Liquid	Fluid medium with a single liquid phase

Downhole Isolation Valve A downhole isolation device placed in the wellbore to isolate downhole pressure from surface that can be activated by hydraulic or mechanical means and can be recovered or left in the well permanently.

DWOP Drilling the Well On Paper

ECD Equivalent Circulating Density

EMW Equivalent Mud Weight

Energy-Ignition Source Any source of energy or heat that has the potential to ignite an explosive or flammable mixture (Energy Safety Canada Fire and Explosion Hazard Management Guideline).

EPZ Emergency Planning Zone

Erosion The wear of material by mechanical means.

ERP Emergency Response Plan

ESD Emergency Shut Down (Valve)

FIT Formation Integrity Test

Flow Drilling Achieving underbalanced conditions by relying on reservoir pressure which may result in hydrocarbons being produced to surface.

Flush Production The initial high production rate exhibited by a permeable feature when first encountered in a UBD operation.

H_2S Hydrogen Sulphide

Hard Shut-in The process of closing in a flowing well with the BOP that has the choke line closed.

HAZID Hazard Identification

HAZOP Hazardous Operations

HCR Hydraulic Control Remote

HPHT High Pressure High Temperature

HSE Health Safety and Environment

IADC International Association of Drilling Contractors

ID Inside Diameter

Influx See definition of Kick.

IRP Industry Recommended Practice

ISO International Standards Organization

Kick Any unintended entry of water, gas, oil, or other formation fluid into a wellbore that is under control and can be circulated out.

LEL Lower Explosive Limit

Lithology The macroscopic nature of the mineral content, grain size, texture and colour of rocks. (Source: SLB Oilfield Glossary)

LOT Leak-Off Test

MACP Maximum Allowable Casing Pressure

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 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 to the surface. Any influx incidental to the operation will be safely contained using the appropriate process.

Maximum Allowable Casing Pressure (MACP) The highest wellhead pressure possible without fracturing exposed formations below the casing shoe. It is usually determined from Formation Integrity Tests or similar tests.

MASP Maximum Anticipated Surface Pressure

MPD Managed Pressure Drilling

MPSP Maximum Predicted Surface Pressure

Mud Ring A buildup of cuttings in the return conduit.

Multi-phase Drilling Fluid System A drilling fluid intentionally engineered, comprised of a liquid and a gaseous phase.

MWD Measurement While Drilling

NACE National Association of Corrosion Engineers

NPT Non-Productive Time

NRV Non-Return Valve

NS-NRV Near Surface Non Return Valve

Nuisance Gas For purposes of IRP 22, nuisance gas could be one or more of the following:

- Trip gas
- Drill gas
- Bottoms-up gas
- Connection gas

> **Note:** A continuous flare may indicate that there is more than nuisance gas being dealt with. At this point it is necessary to review job parameters and equipment limitations to confirm that RMD is still appropriate (see 22.8.5.1 RMD Operations Matrix).

OD Outside Diameter

P&ID Piping & Instrumentation Diagram

PFD Process Flow Diagram

Pipe Heavy A pipe heavy condition exists when the weight of the drill string and BHA exceed the pressure-area product of the wellhead pressure and the cross-sectional area of the pipe or connection being stripped.

Pipe Light A pipe light condition exists when the pressure-area product of the wellhead pressure and the cross-sectional area of the pipe (or connection) being stripped exceeds the weight of the drill string and BHA.

Piping and Instrumentation Diagram/Drawing (P&ID) A Piping and Instrumentation Diagram/Drawing is a detailed schematic of the intended RMD/MPD/UBD rig up and integration with the conventional drilling plan. It is typically negotiated, and hazard assessed between the RMD/MPD/UBD Service Provider, the Drilling Contractor and the Operator's design personnel.

PPB Parts Per Billion

PPE Personal Protective Equipment

PPM Parts Per Million

Process Flow Diagram (PFD) IRP 22 defines a Process Flow Diagram as a simplified schematic of a P&ID to show the flow paths and equipment involved in the operations.

PWD Pressure While Drilling

PVT Pressure, volume, temperature (analysis)

RCD Rotating Control Device

Returns Management Drilling (RMD) A drilling activity where hydrostatic drilling fluid weight could be less than the pore pressure of the formation but the well is not believed to be capable of flow to surface. The intention is to handle/respond to nuisance gas at surface with appropriate equipment.

Risk The combination of the probability of an event and its consequences (as per ISO).

RMD Returns Management Drilling

ROP Rate of Penetration

RPM Revolutions Per Minute

SAGD Steam-assisted Gravity Drainage

SBP Surface Backpressure

SEM Scanning Electron Microscope

Single-phase Drilling Fluid System A drilling fluid comprised of only a liquid phase.

Single-phase MPD Operations MPD operations using a single fluid system.

SO_2 Sulphur Dioxide

Soft Shut-in In well control operations, closing the BOPs with the choke and HCR, or fail-safe, valves open. (Compare hard shut-in.)

SOP Standard Operating Procedure

Stakeholders All parties involved in the operation (e.g., operator, service provider, rig contractor, etc.).

UBD Underbalanced Drilling

UEL Upper Explosive Limit

Underbalanced Drilling (UBD) A drilling activity employing appropriate equipment and controls where the pressure exerted in the wellbore is intentionally less than the pore pressure in any part of the exposed formations with the intention of bringing formation fluids to the surface.

UT Ultrasonic Thickness

WBE Well Barrier Envelope

W**ell Barrier** An envelope of one or several dependent barrier elements preventing fluids or gases from flowing unintentionally from the formation, into another formation or to surface (as per NORSOK D-010).

Well Barrier Element A medium/equipment/object that alone cannot prevent flow from one side to the other side of itself (as per NORSOK D-010).

Well Classification The following table outlines well classification information as per IADC.

Table 29. IADC Well Classifications

Classification	Description
Level 0	Performance enhancement only, no hydrocarbon containing zones.
Level 1	Well incapable of natural flow to the surface. Well is “inherently stable” and is a low level of risk from a well control point of view.
Level 2	Well capable of natural flow to surface but enabling conventional well kill methods and limited consequences in case of catastrophic equipment failure.
Level 3	Geothermal and non-hydrocarbon production. Maximum shut-pressure is less than UBO equipment operating pressure rating. Catastrophic failure has immediate serious consequences.

Classification	Description
Level 4	Hydrocarbon production. Maximum shut-in pressure is less than UBD equipment operating pressure rating. Catastrophic failure has immediate serious consequences.
Level 5	Maximum projected surface pressures exceed UBD operating pressure rating but are below BOP stack rating. Catastrophic failure has immediate serious consequences.

Appendix K: References and Resources

DACC References

Available from www.energysafetycanada.com

- Energy Safety Canada Fire and Explosion Hazard Management Guidelines
- IRP 01: Critical Sour Drilling
- IRP 02: Completing and Servicing Sour Wells
- IRP 04: Well Testing and Fluid Handling
- IRP 07: Competencies for Critical Roles in Drilling and Completions
- IRP 08: Pumping of Flammable Fluids
- IRP 14: Non-Water Based Drilling Fluids
- IRP 20: Wellsite Design Spacing Recommendations

Local Jurisdictional Regulations and Information

Alberta

Available from www.alberta.ca:

- Occupational Health and Safety Act, Code, and Regulations
- Risk Management and Hazard Assessment
- Ambient Air Quality Objectives/Regulations
- Petroleum Industry Incident Support Plan
- Pre-Project Meeting Guidelines

Available from www.aer.ca

- Oil and Gas Conservation Act and Rules
- Directive 007-1: Allowables Handbook
- Directive 010: Minimum Casing Design Requirements
- Directive 017: Measurement Requirements for Oil and Gas Operations
- Directive 036: Drilling Blowout Prevention Requirements and Procedures
- Directive 037: Service Rig Inspection Manual
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