DACC

DRILLING AND COMPLETION COMMITTEE

IRP 1 : Critical Sour Drilling

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

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CANADIAN ASSOCIATION OF PETROLEUM PRODUCERS

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This IRP is a set of best practices and guidelines compiled by knowledgeable and experienced industry and government personnel. It is intended to provide the operator with advice regarding the specific topic. It was developed under the auspices of the Drilling and Completions Committee (DACC).

The recommendations set out in this IRP are meant to allow flexibility and must be used in conjunction with competent technical judgment. It remains the responsibility of the user of this IRP to judge its suitability for a particular application.

If there is any inconsistency or conflict between any of the recommended practices contained in this IRP and the applicable legislative requirement, the legislative requirement shall prevail.

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Table of Contents

List of Figures and Equations

List of Tables

1.0 Preface

1.0.1 Purpose

This document contains a collection of Industry Recommended Practices (IRPs) and guidelines to prevent a blowout while drilling a critical sour well. More specifically, overbalanced drilling of high H_2S (sour) wells using jointed drill strings on conventional drilling or modified service rigs. It comprises a set of equipment specifications, practices and procedures to address sour drilling issues and is intended to supplement the normal good drilling practices applied by competent operators.

The recommendations set out in this IRP are meant to allow flexibility and must be used in conjunction with competent technical judgment. The user of the IRP must judge its suitability for a particular application.

Knowledgeable and experienced industry and government personnel compiled these guidelines and practices.

1.0.2 Audience

This document is primarily intended for the drilling sector of the oil and gas industry. More specifically, the intended audience is competent, experienced and knowledgeable drilling personnel with a working knowledge of drilling operations and sour drilling issues.

This document is not intended to be a complete compilation of, or replacement for, good drilling practices or as a guide for inexperienced personnel. Further discussion of the experience and competencies expected is given in sections 1.3 Planning and 1.13 Wellsite Personnel.

1.0.3 Scope and Limitations

This IRP applies to overbalanced drilling using jointed drill strings. For underbalanced drilling consult IRP6: Critical Sour Underbalanced Drilling. For drilling with continuous tubing (coil tubing) consult IRP21: Coil Tubing Operations. In the absence of IRP21, consult IRP6: Critical Sour Underbalanced Drilling.

In case of inconsistency or conflict between any of the recommended practices contained in the IRP and the applicable legislative requirement, the legislative requirement shall prevail.

1.0.4 Revision Process

IRPs are developed by the Canadian Association of Petroleum Producers' (CAPP) Drilling and Completions Committee (DACC) with the involvement of both the upstream petroleum industry and relevant regulators. Enform acts as administrator and publisher.

The DACC will formally review the need to revise IRP 1 every two years considering changes in scope, purpose, technology, practices, etc. Enform will track review dates and bring them to DACC's attention when required.

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 Enform website at www.enform.ca.

1.0.5 Review History

ARP 1 Critical Sour Well Drilling was published in 1987 in response to the findings of the Lodgepole Blowout Inquiry Panel (ERCB Decision Report 84-9). ARP 1 was reviewed in 1993 but no significant revisions were identified. In 1999, DACC determined that improvements in practices warranted a rigorous review. ARP 1 was revised to IRP 1 and sanctioned in January, 2002. For assistance in comparing ARP 1 to IRP 1, refer to Appendix A - ARP to IRP Conversion. During 2002 and 2004, minor editing and technical corrections to Section 1.4 Casing Design and Metallurgy and Section 1.9 Welding were addressed and sanctioned in January 2004. The revisions are summarized in Appendix A - 2003 Revisions. In 2004 the IRP was revised to the new IRP Style Guide and released for industry review. In 2010 through 2014, a review committee revised this current version and it was sanctioned in 2014. These changes are summarized in Appendix A - 2014 Revisions.

1.0.6 Sanction

The following organizations have sanctioned this document:

Canadian Association of Oilwell Drilling Contractors (CAODC)

Canadian Association of Petroleum Producers (CAPP)

Petroleum Services Association of Canada (PSAC)

Explorers & Producers Association of Canada (EPAC)

1.0.7 Acknowledgements

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1.0.8 Range of Obligations

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

Table 2. Range of Obligations

Term	Usage
Must	A specific or general regulatory and/or legal requirement that must be followed.
Shall	An accepted industry practice or provision that the reader is obliged to satisfy to comply with this IRP
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

1.0.9 Symbols

ksi√in: Kilopounds per square inch root inch (ksi is thousands of pounds per square inch)

MPa√m: Megapascals root metre

1.0.10 Abbreviations and Acronyms

AER: Alberta Energy Regulator (formerly ERCB, AEUB)

BHA: Bottomhole Assembly

BOP: Blowout Preventer

CLR: Crack Length Ratio

CTR: Crack Thickness Ratio

DCB: Double Cantilever Beam (samples for Method D testing)

DST: Drillstem Test

EPZ: Emergency Planning Zone

ERP: Emergency Response Plan

ERW: Electric resistance-welded

HB: Brinell Hardness Number

HCR: Hydraulic Control Remote (Valve)

HIC: Hydrogen-Induced Cracking

HRC: Rockwell Hardness Scale “C”

HWDP: Heavy Weight Drill Pipe

IPM: Instrument Performance Model

LCM: Lost circulation material

LPI: Liquid Penetrant Inspection

MAWP: Maximum Allowable Working Pressure

MPI: Magnetic Particle Inspection

NDE: Non-Destructive Evaluation

PQR: Procedure Qualification Record

SMYS: Specified Minimum Yield Stress

SOHIC: Stress-Oriented Hydrogen-Induced Cracking

SSC: Sulphide Stress Cracking

TDG: Transportation of Dangerous Goods by Ground

WHMIS: Workplace Hazardous Materials Information System

WPS: Weld Procedure Specification

1.0.11 Definitions

Blowout: IRP 1 uses the definition of Blowout as specified in AER Directive 056: Energy Development Applications and Schedules.

A well where there is an unintended flow of wellbore fluids (oil, gas, water, or other substance) at surface that cannot be controlled by existing wellhead and/or blowout prevention equipment, or a well that is flowing from one formation to another formation(s) (underground blowout) that cannot be controlled by increasing the fluid density. Control can only be regained by installing additional and/or replacing existing surface equipment to allow shut-in or to permit the circulation of control fluids, or by drilling a relief well.

Engineering Assessment: IRP 1 uses the definition of engineering assessment as specified in IRP 3: In Situ Heavy Oil Operations.

A documented assessment of the effect of relevant variables upon fitness for service or integrity of a casing string, conducted by, or under the direct supervision of, a competent person with demonstrated understanding and experience in the application of the engineering and risk management principles related to the issue being assessed.

Engineering assessments carried out for the purpose of design or material qualification and selection include, where applicable, the following:

- Consideration of the design basis including
  - injection, production and service fluids,
  - operating pressure and temperature range and
  - general and local loading conditions anticipated throughout the well lifecycle.
- Material specifications and properties.
- Historical performance data.
- Environmental conditions and potential environmental consequences.
- Worker/public safety.
- Consequences of failure.

Kick: A flow of formation fluids into the wellbore during drilling operations.

1.1 Background and References

1.1.1 Background

In October 1982, a blowout occurred at a sour gas well being drilled at Lodgepole, AB. The well was out of control for 68 days. For 23 of those days the well was not ignited. 28% H_2S gas flowed at an estimated rate of 150 million cubic feet (4,200,000 m^3) per day. The well also produced 20 thousand barrels per day (3,200 m^3/d) of sulphur-contaminated, orange-coloured condensate. In December, a 12-tonne blowout preventer was placed over the burning well. Crews bled the well of excess gas and pumped heavy drilling mud down to kill the well.

After an 11 week public inquiry, the findings of the Lodgepole Blowout Inquiry Panel (ERCB Decision Report 84-9) were released in December 1984 and prompted the creation of ARP 1 Drilling Critical Sour Wells. The goal of ARP 1 was to provide a set of best practices to prevent a blowout while drilling a critical sour well.

The topics covered by ARP 1 were selected by the Blowout Prevention Review Committee based on the panel findings and general industry best practices of the day. During 2000, ARP 1 was reviewed and a hazard assessment conducted to confirm all hazards that could potentially lead to a blowout on a critical sour well had been identified. With the result of the hazard assessment and other enhancements, ARP 1 evolved into IRP 1 Critical Sour Drilling sanctioned in January 2002. IRP 1 currently provides the best practices to address all of the hazards identified in the hazard assessment.

1.1.2 References and Links

This document references many standards, codes, decisions and documents. The full name, version and date of the publication are detailed in the Codes and Standards section at the beginning of most chapters. For the remainder of the chapter, a shortened form of the code or standard is used to ease readability. During each review these references are reviewed for relevance.

Links to external web sites or internal chapters appear in the document. At the time of writing, all links are up-to-date and active. If you find a misdirected or broken link please email safety@enform.ca so the link can be updated.

1.1.3 Well Types

IRP 1 allows some flexibility based on the following criteria:

- Complexity of the well (geology and well design).

- Potential impact to the public (magnitude of the H_2S release rate and proximity to the public).
- The simplicity or difficulty of evacuation (number of affected public and any evacuation issues).

Certain options may be used depending on the combination of these criteria. These options must be discussed in the project plan and are discussed in the appropriate IRP chapter. For example:

- Casing setting depth (see 1.4.17 Intermediate Casing)
- Shear Blind Rams (see 1.5.5 Shear Blind Rams)
- Mud-Gas Separators (see 1.7.3 General Requirements)

1.1.3.1 Low Complexity Well

A well is considered low complexity if it is in a known area with no drilling problems based on the geological prognosis of the proposed well. To qualify

1. the well must be in a known and established field area that offsets existing development,
2. a summary of offset wells confirms that no significant lost circulation problems or other adverse drilling conditions are expected and
3. a summary of drillstem test pressures, mud densities or other information verifies that normal formation pressures are expected.

A low complexity well would have less uncertainty and therefore a lower risk of problems due to well conditions.

Typically, this would mean a development well may be a low complexity well while an exploration well would not.

1.1.3.2 Low Impact Well

A well is considered to have low potential impact to the public if it has a low H_2S release rate and/or is not in close proximity to public. The guidelines are as follows:

- Maximum potential H_2S release rate is less than 3 m^3/s.
- Calculated Emergency Planning Zone (EPZ) does not intersect an urban centre.

1.1.3.3 Simple Emergency Response Plan Well

A well would have a simple Emergency Response Plan (ERP) if EPZ evacuation is relatively easy. To qualify the calculated EPZ must encompass fewer than 10 occupied dwellings and have no terrain, communication, evacuation route or weather issues.

1.2 Hazard Assessment

1.2.1 Scope

The purpose of the hazard assessment was to determine whether all hazards that could lead to a critical sour well blowout had been identified in ARP 1.

The hazard assessment was conducted using well-established methodologies as described in ISO 17776:2000, Petroleum and Natural Gas Industries – Offshore Production Installations – Guidelines on Tool and Techniques for Hazard Identification and Risk Assessment.

The assessment included the following:

1. Hazard Identification: Identified all significant hazards associated with the drilling of a critical sour well that could lead to a blowout.
2. Hazard Control Identification: Identified one or more design controls and/or practices to prevent the hazard from escalating to a blowout.
3. IRP 1 Control Review: Identified the IRP 1 chapter relating to each control.

1.2.2 Results

The majority of hazards had been addressed in ARP 1 but this assessment identified a few minor areas that the draft IRP 1 had not addressed (e.g., fishing operations). The review committee updated IRP 1, most notably in sections 1.3 Planning and 1.14 Practices, to address the additional items. In the view of the ARP 1 Review Committee, the practices outlined in the revised IRP 1 adequately provided the appropriate controls to address all identified hazards.

1.2.3 The Blowout Sequence

A kick occurs when formation fluids enter the wellbore during drilling. If the kick is not controlled a blowout can occur.

A blowout is a full uncontrolled release of fluids into the atmosphere.

During normal operations the drilling fluid hydrostatic pressure keeps formation fluids from entering the wellbore. However, several circumstances (hazards) can cause a kick (see 1.2.4 Hazards).

After a kick occurs, well control equipment and procedures are used to control and safely dispose of the formation fluid. An uncontrolled release can occur if a well control malfunctions or there is an error in procedures.

If control cannot be regained using the equipment on location (e.g., shut in with the wellhead valve, shut in with blowout prevention equipment, directing the fluids to a flare, etc.) a blowout occurs. The blowout is brought under control using specialized blowout control equipment and practices or by drilling a relief well.

1.2.4 Hazards

The hazard assessment identified six hazards that could lead to a kick:

1. Insufficient mud weight to control reservoir pressure
2. Drilling into an unexpected high pressure formation
3. Loss of circulation or returns resulting in loss of hydrostatic head (which may cause the well to flow)
    a. Losses prior to tripping
    b. Plugging the drill pipe with lost circulation material (LCM)
4. Improper tripping practices
    a. Swabbing/surging while tripping (rapid tripping increases swabbing)
    b. Improper hole fill-up during tripping
5. Error in other operations
    a. Drillstem Test (DST)
    b. Coring
    c. Fishing
    d. Logging
    e. Casing running and cementing
    f. Insufficient fluid density
6. Human error

Once a kick occurs there are several escalating factors (E) that can lead to a blowout if the well is not controlled properly:

E1: Slow well shut-in procedures resulting in a large kick.

E2: Inappropriate equipment for well conditions (e.g., size, pressure rating, etc.).

E3: Material and/or equipment failure due to sour fluid exposure.

E4: Equipment wear or improper maintenance.

E5: Ineffective execution of well control procedures.

E6: Flow inside the drill pipe.

E7: Problems encountered in the open wellbore during kick circulation (e.g., lost circulation, formation breakdown, wellbore collapse, etc.).

1.2.5 Hazards, Controls and IRP 1 Reference

The following table summarizes the hazards identified above, identifying the controls and IRP reference associated with each hazard.

Table 3. Hazards, Controls and IRP 1 Reference

Hazard	Control (Design or Practice)	IRP 1 Reference
1. Insufficient mud weight	Design: Drilling program specifies appropriate mud weight	1.3.3 Project Plan
	Practice: Follow drilling program	1.13.2 Roles and Responsibilities 1.13.3 Supervision and Crew Requirements 1.14.13 Reviews and Safety Meetings
	Practice: Monitor well conditions and increase weight as required	1.10.2 Drilling Fluid Density 1.11.5 Monitoring Indirect Indicators
2. Unexpected high pressure formation	Practice: Monitor well conditions and increase weight as required	1.10.2 Drilling Fluid Density 1.11.5 Monitoring Indirect Indicators
3. Loss of circulation	Design: Drilling program specifies appropriate mud weight	1.3.3 Project Plan
3a. Losses prior to tripping pipe	Design: Intermediate casing or open hole integrity test isolates possible loss zones	1.3.3 Project Plan 1.4.17 Intermediate Casing
	Practice: Monitor well conditions and adjust mud properties as required	1.10.2 Drilling Fluid Density 1.11.5 Monitoring Indirect Indicators
3b. Plugging drill pipe with LCM	Design: Drilling program identifies potential problems and actions (e.g. pump out sub)	1.3.3 Project Plan
4. Improper tripping practices	Design: Drilling program specifies hole sizes, BHA and mud weights for proper trip margin	1.3.3 Project Plan
4a. Swabbing/surging	Design: Mud properties designed to minimize swabbing	1.10.4 Rheological Properties
4b. Improper hole fill up	Practice: Follow tripping procedures and monitor trip tank	1.11.4 Trip Tanks 1.13.3 Supervision and Crew Requirements 1.13.4 Minimum Qualifications 1.14.6 Tripping Practices
5. Other Operational Errors		

Hazard	Control (Design or Practice)	IRP 1 Reference
5a. DST	Practice: Follow IRP1	1.14.7 Drillstem Testing
5b. Coring	Practice: Follow IRP1	1.14.9 Coring
5c. Fishing	Practice: Follow IRP1	1.14.10 Fishing Operations
5d. Logging	Practice: Follow IRP1	1.14.11 Logging
5e. Casing Running/ Cementing	Practice: Follow IRP1	1.14.12 Casing and Liner Running
5f. Insufficient Fluid Density	Practice: Confirm well conditions prior to starting operations	1.10.2 Drilling Fluid Density 1.11.5 Monitoring Indirect Indicators
6. Human Error	Design: Drilling program developed by qualified personnel with appropriate scrutiny and approval	1.3.2 Project Approval 1.3.3 Project Plan
	Design: Supervisors and crew meet competency requirements	1.3.2 Project Approval 1.3.3 Project Plan 1.13.4 Minimum Qualifications
	Practice: BOP drills to improve competency	1.14.4 BOP Drills 1.14.6 Tripping Practices 1.14.13 Reviews and Safety Meetings

The following table identifies the controls for a kick and the escalation factors that can lead to a blowout.

Table 4. Kick Escalation Factors, Controls and IRP 1 Reference

Kick Escalation Factor	Control (Design or Practice)	IRP 1 Reference
Improper well control procedures after kick	Practice: Effective well control procedures: Shut in well, circulate out kick and regain well control	1.13.2 Roles and Responsibilities 1.13.3 Supervision and Crew Requirements 1.13.4 Minimum Qualifications 1.14.4 BOP Drills
	Practice: Implement ERP	1.3.4 Emergency Response Plan 1.14.13 Reviews and Safety Meetings
	Design: Redundant well control equipment	1.5 Blowout Preventer Stack 1.6 Choke Manifold 1.7 Mud-Gas Separators
E1. Slow shut-in procedures resulting in a large kick	Practice: Well conditions monitored	1.11 Kick Detection
E2. Improper Equipment	Design: Drilling program identifies appropriate size and pressure requirements	1.3.3 Project Plan

Kick Escalation Factor	Control (Design or Practice)	IRP 1 Reference
E3. Material and/or equipment failure due to sour fluid exposure	Design: Equipment meets sour service requirements	1.4 Casing Design and Metallurgy 1.5 Blowout Preventer Stack 1.6 Choke Manifold 1.7 Mud-Gas Separators 1.8 Drill String Design and Metallurgy 1.9 Welding
E4. Equipment wear or improper maintenance	Practice: Keep equipment in good working order with regular inspection and tests	1.14.2 Rig Inspections 1.14.3 Pressure Testing
E5. Ineffective execution of well control	Practice: Effective kick detection and rapid shut-in	1.13.4 Minimum Qualifications 1.14.4 BOP Drills
E6. Flow inside the drill pipe	Design: Use a float valve and stabbing valve to prevent flow up drill string	1.8.10 Downhole Floats 1.8.11 Upper Kelly Cocks, Lower Kelly Cocks and Stabbing Valves
E7: Open wellbore problems	Design: Intermediate casing to minimize open hole	1.4.17 Intermediate Casing

1.3 Planning

1.3.1 Scope

The purpose of this chapter is to outline the planning and review practices that should be conducted to ensure technical and safety integrity of a critical sour drilling project.

1.3.2 Project Approval

IRP The overall project plan for drilling a critical sour well 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.

1.3.2.1 Flexibility and Technical Judgment

Due to the complexity of a critical sour drilling project, and to allow for continuous improvement regarding safety and operational efficiency, IRP 1 recommendations are meant to allow flexibility. Competent technical judgment must be used in conjunction with these recommendations.

It is the operator's responsibility to ensure the required technical judgment is used to develop the project plan and during the project execution.

1.3.2.2 Engineering Assessments

IRP 1 allows flexibility in practices in several instances provided an engineering assessment is performed and approved.

It is the operator's responsibility to ensure the engineering assessment is performed by personnel qualified by normal industry standards (e.g., years of technical or operational experience, review of applicable completed projects, references, etc.) and is able to demonstrate qualifications upon audit.

1.3.3 Project Plan

IRP A drilling project plan (drilling program) must be developed for each well. The project plan contents are outlined in the following sections and are based on AER Directive 056: Energy Development Applications and Schedules).

Copies of the project plan must be

- on site during drilling operations,
- filed with the appropriate governmental field office (as required) for use during a site inspection and
- available for audit of the application for the well license or filed with the well license application if the application is to be reviewed at a public hearing.

1.3.3.1 Objectives

The objective of the project plan is to document the well design, equipment and practices to be used during project execution.

A key use of the plan is to provide direction to wellsite personnel. The plan must have enough detail for wellsite personnel to clearly understand the potential hazards and required actions.

For areas of common practice with no variance from normal operations, a brief overview can be provided with references to more detailed discussion (e.g., this IRP).

1.3.3.2 Contents

The project plan contents are based on AER Directive 056: Energy Development Applications and Schedules) and are summarized in the table below.

Table 5. Project Plan Contents

Contents	Description	IRP 1 Reference
Geological Setting	1. Discuss the expected geological zones, including identification of sour and critical sour zones. 2. Conduct an offset well data search to a minimum 5 km radius from the subject well. • Review data from current wells with a similar geology and depth to get a clear understanding of potential problems and design issues. Examination of the wells at greater distances may be required to ensure all relevant information is reviewed. • Include an Offset Well Map that indicates all similar offset wells. • Summarize offset well data and reference the Offset Well Map. Note: Offset well data (well files, logs and drilling event data) can be obtained from governmental agencies and commercial service companies. Note: Some information regarding wells may be confidential for a period of time after an offset well has been drilled. However, for critical sour wells, an informal discussion is recommended with the licensee of a nearby well regarding any potential drilling problems.	

Contents	Description	IRP 1 Reference
Calculation of H_2S release rate	• H_2S release rate calculations should follow "H_2S Release Rate Assessment Guidelines and Audit Forms", CAPP, 1999. • Summarize the assessment.	
Problems and well design	Review and summarize offset well information. Include the following information: • Hole problems expected • Solutions • Reasons for selecting casing setting depths	
Emergency Response Plan	Include an overview of the ERP with regard to the degree of difficulty in implementing the plan.	1.3.4 Emergency Response Plan
Well Type	Discuss the well type.	1.1.3 Well Types
Casing Design	• Supply casing details (casing depth, grade, weight, size) for surface, intermediate and production casing. • Supply details of the surface-casing bowl. • Supply details of casing design and sour service suitability of the casing upgrades. If grades other than L-80 are proposed, details on chemistry specifications must be reviewed and documented. Note: Casing design for horizontally drilled wells must address the additional stresses and loads.	1.4 Casing Design and Metallurgy
Blowout Prevention Equipment	• Identify BOP stack configuration and pressure rating. • Include reasoning if blind shear rams are not planned. • Supply the choke manifold configuration and pressure rating. • Identify the number of mud gas separators planned. Include reasoning if only one mud gas separator is planned.	1.5 Blowout Preventer Stack 1.6 Choke Manifold 1.7 Mud-Gas Separators
Drill String	Summarize the grade, type (new or used) and class of drill pipe.	1.8 Drill String Design and Metallurgy
Drilling Fluids	• Summarize the type, density, pH level and amount of weight material on site. • Identify whether the system will be pretreated with an H_2S scavenger. • Identify the type of additional drilling fluid to be kept on site.	1.10 Drilling Fluids
Kick Detection	Summarize the kick detection and monitoring equipment to be used.	1.11 Kick Detection
Wellsite Safety	Summarize the wellsite safety equipment and procedures to be used.	1.12 Wellsite Safety
Inspection Equipment Testing Procedures	Describe the inspection and testing procedures for ensuring that all equipment is fully operational prior to the well reaching the critical depth and procedures to ensure a state of readiness is maintained.	1.14 Practices

Contents	Description	IRP 1 Reference
Wellsite Personnel	Describe the wellsite personnel and their qualifications.	1.13 Wellsite Personnel
Practices	Describe any special practices (e.g., Tripping, Coring, Directional surveys).	1.14 Practices
Blowout Insurance	Provide a statement that the company, including working interest owners, is self-insured. Otherwise, other proof of insurance must be filed and available for audit. • Companies applying to license a critical sour well must either be self-insured to cover the costs of a blowout or must obtain significant liability insurance. • Insurance amounts depend on the well depth and must include a provision for pollution and seepage, evacuation expense, underground blowout, care/custody and control. • If the well is a joint venture, the company must either hold insurance for 100% of the working interest or have a copy of insurance policies for the interest of each partner.	
Wellbore Diagram	Summarize the following information from the project plan in a Wellbore Diagram: • Geological setting and formation expected • H_2S release rates • Hole problems • Casing design • Formation pressure, equivalent drilling fluid density or formation pressure gradient Review the Wellbore Diagram with rig crews and post a copy in the doghouse.	1.14 Practices

1.3.4 Emergency Response Plan

IRP A site-specific Emergency Response Plan (ERP) must be developed for each critical sour well. This plan must be approved by the appropriate governmental agency responsible for public safety.

1.3.4.1 Overview

The AER Directive 71: Emergency Preparedness and Response Requirements for the Petroleum Industry should be used as a minimum standard for developing an ERP for drilling a critical sour well. Any applicable regulations of the jurisdictional agency approving the ERP must be adhered to and any uniqueness in those regulations taken into account.

Each plan must consider site-specific circumstances. Variations in the plans can be expected based on factors such as the geological prognosis of the well, population density and distribution, and the consequences of a blowout.

Public input from local residents, municipal administrators and first responders is an integral part of preparing an effective ERP. In some instances it may be necessary to hold public meetings to obtain this input.

A copy of the approved ERP must be on site during drilling operations, prior to drilling out the surface casing and during all completion or servicing operations of designated critical sour wells. Copies must also be sent to the appropriate jurisdictional agencies and response providers as noted in the jurisdictional legislation and as agreed to by the affected parties.

1.3.4.2 Emergency Planning Zone

The appropriate Emergency Planning Zone (EPZ) must be carefully selected and must be adequate to ensure the safety of the public near the well. The size and shape of the zone must reflect the maximum drilling H_2S release rate but must also have regard for the local terrain, population density and access/egress routes through the EPZ. Consult the jurisdictional agency approving the ERP for specific requirements.

1.3.4.3 Contents

The ERP contents listed below are basic contents only. Consult the jurisdictional agency approving the ERP for specific requirements.

Table 6. Emergency Response Plan Contents

Contents	Description
Summary	Summarize the key facts about the proposed well and the emergency response plan. This should be consistent with any information found in the resident information package.
Emergency Definition and Action	• Describe the various circumstances that could lead to a sour gas release and the intended response. • Define the various stages of an emergency and describe the action for each stage. • Describe the responsibilities of the company, agency and response personnel involved in any stage of the emergency. • Describe how responses will be prioritized. • Describe recovery procedures to be used after the emergency. • Describe the emergency organization and incident management system to be used.
Public Protection Measures: Evacuation Procedures	Define the criteria used to initiate an evacuation and describe how the evacuation is to be carried out. • Address details regarding the air quality monitoring program and communication procedures. • For critical sour wells where the EPZ includes all or a portion of a densely populated area (e.g., an acreage development or an urban centre), additional stationary and mobile air quality monitoring units are required during the drilling operations in the critical sour zone(s) until the wellbore is isolated by casing or cement plug.

Contents	Description
Public Protection measures: Shelter in Place	• Define the criteria used to determine if shelter indoors is a viable protection measure (instead of, or along with, evacuation of the public). • Include instructions for shelter in place.
Public Protection Measures: Ignition	Define the ignition criteria and circumstances leading to the deliberate ignition of the well. Note: There must be a clear and specific plan in place to ignite an uncontrolled flow of sour gas, consistent with the ignition criteria, which needs to take into account un-evacuated public, H_2S concentrations, effectiveness of monitoring and any lack of control over the release.
Resident Information Package	Include a copy of the Resident Information Package that is to be provided to residents within the EPZ. The package provides a brief summary of the proposed well and operator, a summary of evacuation and ignition procedures, emergency telephone numbers and a description of the hazards of H_2S and sulphur dioxide.
Contact Information	List the residents, company personnel, affected agencies, response organizations and suppliers to contact in the event of a sour gas release.
Maps	Include the necessary maps to show • the selected EPZ and the surface developments, roads, topographical features and any other criteria established by the jurisdictional legislation, • the emergency awareness zone and • the immediate hazard and response zones.
Appendices	Include all relevant information that could possibly be required to prepare for and respond to a sour gas emergency. Items to consider are as follows: • Glossary of terms • ERP application documents • Information about H_2S exposure • Emergency level designation criteria • Evacuation criteria • Shelter in place criteria and instructions • Ignition criteria • Communication and notification requirements • Forms required during an emergency event

1.3.4.4 Implementation

The initial phase(s) of the ERP are implemented during the initial stages of any well control incident. The severity of the incident determines the extent of implementation of the ERP. Refer to AER Directive 071: Emergency Preparedness and Response Requirements for the Petroleum Industry Appendix 4 – Assessment Matrix for Classifying Incidents for details about classifying incidents in Alberta.

1.4 Casing Design and Metallurgy

1.4.1 Scope

1.4.1.1 Casing Design

The scope for casing design includes the following:

- Basic casing design (burst, collapse and tension) following the appropriate regulatory requirements.
- A design factor for burst design to ensure the specified casing would not approach its specified minimum yield stress (SMYS) and thus be more susceptible to Sulphide Stress Cracking (SSC).
- Recommended practice for intermediate casing.

Recommended practices apply to the last casing string set prior to the well becoming critical (typically intermediate but possibly surface casing) and production casing. For re-entry wells the practices apply to both new and existing casing.

1.4.1.2 Casing Metallurgy

The recommended practices apply to carbon and low alloy steel casing and coupling grades. The scope does not include corrosion, the use of corrosion-resistant alloys or corrosion control.

1.4.1.3 Casing and Coupling Grades

This IRP refers to grades of casing and couplings referenced in API 5CT. The grades are as follows:

- J55, seamless or electric resistance-welded (ERW)
- K55, seamless or ERW
- L80 Type 1 (L80-1), seamless or ERW
- C90 Type 1 (T90-1) seamless
- T95 Type 1 (T95-1) seamless
- C110 seamless

1.4.1.4 Environmental Degradation Mechanisms

Sour gas contains hydrogen sulphide (H_2S) and carbon dioxide (CO_2) at various partial pressures and ratios. These gases make any aqueous environment acidic and potentially corrosive. In addition, the presence of hydrogen sulphide may make the casing and coupling materials susceptible to environmental embrittlement mechanisms.

IRP 1 addresses three environmental degradation mechanisms that may be active when the casing and couplings are exposed to sour gas:

- Sulphide Stress Cracking (SSC), which may be active in all casing and coupling grades listed.
- Hydrogen-Induced Cracking (HIC), which may be active in seamless or ERW J55 and K55. Tensile stress is not necessary for the initiation and growth of HIC.
- Stress-Oriented Hydrogen-Induced Cracking (SOHIC), which may be active in seamless or ERW J55 and K55.

Quench and Tempered microstructures typically have high resistance to HIC and SOHIC.

SSC may occur very quickly (within minutes to hours) upon exposure of susceptible casing and couplings to sour gas. The rapidity depends on the following:

- The level of residual and operating tensile stress.
- Temperature.
- Acidity (pH) of the aqueous environment.
- Partial pressure of H_2S.
- The inherent resistance of the material.

SOHIC and HIC are typically more time-dependent mechanisms although failure by SOHIC may occur within two days in highly susceptible material.

1.4.2 Codes and Standards

The following codes and standards are referenced in this chapter:

- API TR 5C3, Technical Report on Equations and Calculations for Casing, Tubing, and Line Pipe Used as Casing or Tubing; and Performance Properties Tables for Casing and Tubing, First Edition. 2008.
- API Spec 5CT Specification for Casing and Tubing, Ninth Edition. 2011.
- API RP 5A5 (R2010) - Field Inspection of New Casing, Tubing, and Plain-end Drill Pipe, Seventh Edition, Includes Errata (2009), 2005.
- NACE MR0175/ISO 15156 Materials for use in H2S-containing environments in oil and gas production, 2009 Edition.
- NACE TM0177 Laboratory Testing of Metals for Resistance to Sulfide Stress Cracking in Hydrogen Sulfide (H_2S) Environments, 2005 Edition.
- NACE TM0284-2011 Evaluation of Pipeline and Pressure Vessel Steels for Resistance to Hydrogen-Induced Cracking, 2011 Edition.

1.4.3 Casing Collapse Design Specifications

IRP Casing collapse design specifications shall be as follows:

- Design for no internal pressure.
- Determine the collapse resistance. The AER Directive 010: Minimum Casing Design and equations in API 5C3 may be used.
- Collapse resistance is reduced by tensile load as per API 5C3.
- The design check should be based on an external fluid gradient of the original drilling fluid density prior to running the casing. Approval may be granted for less (minimum 10 kPa/m) provided the actual fluid gradient does not exceed design gradient.
- Collapse strength is based on remaining wall thickness.
- Safety Factor = 1.0.

1.4.4 Casing Tension Design Specifications

IRP Casing tension design specifications shall be as follows:

- Buoyant effect is neglected.
- Casing wall yield strength is used if yield strength is less than joint strength.
- Tensile strength is adjusted to remaining wall thickness.
- Safety Factor for new wells = 1.6
- Safety Factor for re-entry wells = 1.2

Note: The safety factor is reduced from 1.6 to 1.2 for re-entry wells because an existing casing will not experience the running or cementing loads anticipated in the original design.

1.4.5 Casing Burst Design Specification

IRP Casing burst design specifications shall be as follows:

- Production Casing Internal Pressure = 85% of original maximum producing formation pressure. For a re-entry well, with review and approval based on an engineering assessment, 85% of current maximum producing formation pressure.
- Intermediate Casing Internal Pressure = 85% of maximum producing formation pressure (the same as for the production casing).
- Internal pressure is free to act over the full length of casing string.
- No allowance is made for external pressure.
- Safety Factor = 1.25

Note 1: For Critical Sour Wells the safety factor is increased from the standard of 1 to 1.25. This will ensure that even under maximum load the casing would be at less than 80% of its burst rating and would not approach its SMYS. The lower stress load would greatly reduce the susceptibility to SSC.

Note 2: A lower safety factor may be considered if the casing material meets the NACE TM0177 Method D SSC test acceptance criteria and is also tested using Method A at a stress level at least 10% higher than the intended loading levels. For example, if the safety factor is 1.15 the required test stress level must be 1/1.15 + 10% or in this case, 96% of SMYS. NACE TM0177 test methods are discussed in 1.4.9 NACE Testing Protocols.

Note 3: SSC testing (as per 1.4.10 Sulphide Stress Cracking Test Procedures and Acceptance Criteria) must be conducted on every heat of grades L80-1, C90-1, T95-1 and C110 if the safety factor is less than 1.25.

1.4.6 Casing and Coupling Grades

IRP Adherence to this IRP should ensure that, under normal stressing and environmental exposure situations, casing and couplings have adequate resistance to the following environmental degradation mechanisms:

- Sulphide Stress Cracking (SSC)
- Hydrogen-Induced Cracking (HIC)
- Stress-Oriented Hydrogen-Induced Cracking (SOHIC)

These environmental degradation mechanisms are explained in 1.4.1.4 Environmental Degradation Mechanisms.

The grades permitted are based on API 5CT grades but manufacturers may provide proprietary grades of casing and couplings if proof of resistance to the environmental degradation mechanisms is shown.

IRP Surface casing must be suitable for sour service.

The following grades listed in API 5CT are intended for sour gas exposure and are suitable for use in critical sour gas wells as surface casing:

- J55 and K55 (seamless or ERW)
- L80-1 (seamless or ERW)
- C90-1 (seamless)
- T95-1 (seamless)

- C110 (seamless)

IRP Intermediate and production casing must be suitable for sour service.

The following grades listed in API 5CT are intended for sour gas exposure and are suitable for use in critical sour gas wells at any temperature (as per NACE MR0175/ISO15156-2 SSC Regions 1, 2, or 3) provided that the additional requirements identified in this IRP have been applied:

- L80-1 (seamless or ERW)
- C90-1 (seamless)
- T95-1 (seamless)

C110 (seamless) is intended for sour gas exposure and is suitable for use in critical sour gas wells at any temperature in NACE MR0175/ISO15156-2 SSC Region 1.

The use of C110 in NACE MR0175/ISO 15156-2 SSC Regions 2 or 3 requires an engineering assessment, including simulated environment testing, to validate SSC resistance.

1.4.7 High Temperature Sour Service Casing Grades

IRP The following table outlines the non-sour service-rated grades that may be used in critical sour gas wells provided their operating temperature remains forever above the minimum stated below (as per NACE MR0175/ISO 15156).

Table 7. High Temperature Sour Service Casing Grades

Casing Grade Details	Temperature
C110 and proprietary seamless, Quench and Tempered grades with 758 MPa (110 ksi) maximum yield strength	65°C and above
P110 • Seamless process only • Maximum permitted sulphur 0.010% • Maximum permitted phosphorous 0.020%	80°C and above
Proprietary seamless, Quench and Tempered grades to 965 MPa (140 ksi) maximum yield strength	80°C and above
Q125 Type 1 must be: • Cr-Mo chemistry • Seamless process • Quench and Tempered • 1,034 MPa (150 ksi) maximum yield strength	107°C and above

Operating temperature should be determined with the following considerations:

- An open-hole temperature log run is suggested across the uppermost proposed location of the non-sour service rated casing.
- Casing joints at and below the production packer should be sour service-rated grades because of potential cooling associated with gas production.
- The presence of underground aquifers and their potential effect on the casing and couplings temperature shall be taken into account when specifying non-sour service-rated casing and couplings.
- The presence of intermediate sour formations that non-sour service-rated casing and couplings may be exposed to on the outside diameter during production operations involving temperature dropping (e.g., cold fracturing jobs or acidizing) needs to be considered.

1.4.8 Additional Casing Specifications

IRP The requirements identified below shall be applied, in addition to those of specification of API 5CT, unless sufficient SSC or HIC testing data shows the steel is appropriate for critical sour environments.

Note: This IRP is intended to supplement the requirements of API 5CT. In all cases, API 5CT is the basic specification to which the following enhancements are recommended.

1.4.8.1 Sulphide Stress Cracking Test Requirements

Materials with resistance to SSC shall be qualified using one of the two protocols below:

Protocol 1: Testing of each heat of casing and couplings as per 1.4.9 NACE Testing Protocols.

Protocol 2: Pre-qualification of the manufacturing procedure and subsequent testing of selected casing and couplings as per 1.4.11 Manufacturer Prequalification.

1.4.8.2 Casing Chemical Composition Specifications

Casing and couplings made from steel meeting the minimum chemical composition requirements of each grade listed in API 5CT will not necessarily have adequate resistance to SSC when used in critical sour gas wells and require qualification using protocol 1 above. Once qualified through protocol 1, the steel no longer has to meet the chemical composition in Table 8 below.

The product analysis chemical composition requirements in Table 8 below shall be specified for critical sour gas well casing and couplings (by grade, maximum or permitted range, in weight %) when materials are qualified using protocol 2 above.

Table 8. Chemical Composition Requirements

Element	Maximum or Permitted Range In Weight %					
	J55 and K55	L80-1 ERW	L80-1 Seamless	C90-1	T95-1	C110
Carbon	0.35	0.32	0.32	0.35	0.35[1]	0.35
Manganese	1.40	1.20	1.20[2]	1.00	0.75	0.75
Silicon	0.35	0.35	0.35	0.35	0.35	0.35
Phosphorus	0.020	0.020	0.020	0.015	0.010	0.010
Sulfur	0.010	0.010	0.010	0.005	0.005	0.005
Chromium	[3]	1.30	1.30	0.25-1.20	0.60-1.20	0.60-1.50
Molybdenum	[4]	0.65	0.65	0.15-0.75	0.15-1.00	0.25-1.00
Copper	0.20	0.20	0.20	0.20	0.15	0.15
Nickel	0.20	0.20	0.20	0.20	0.15	0.15
Aluminum	0.040	0.040	0.080	0.080	0.080	0.080
Niobium	0.035	0.040	0.040	0.040	0.040	0.040
Vanadium	[5]	0.050	0.050	0.050	0.050	0.050
Titanium	0.040	0.040	0.040	0.040	0.040	0.040
Boron	0.0025	0.0025	0.0025	0.0025	0.0028	0.0028

The chemical composition requirements for ERW K55 may need to be more restrictive than specified above to ensure resistance to HIC and SOHIC for the following reasons:

- Typically, the level of Carbon, Manganese, Phosphorus and Sulfur must be lower than the maximum specified in the table in order to provide resistance to HIC and SOHIC.
- Calcium treatment may be necessary to eliminate elongated Type II manganese sulphide inclusions. These inclusions have been associated with HIC development.
- ERW J55 and K55 require HIC testing (see 1.4.13 HIC Test Requirements for J55 and K55 Casing).

[1] Carbon may be be increased to 0.35% maximum and Phosphorus may be increased to 0.015% maximum if the molybdenum is 0.50% minimum

[2] Manganese may be increased to 1.40% maximum if the sulfur is 0.005% maximum

[3] Not normally added to this grade

[4] Not normally added to this grade

[5] Not normally added to this grade

1.4.8.3 Hardenability Requirements

IRP Hardenability requirements shall be as follows:

- Grade J55 and K55 casing and couplings have no hardenability requirements.
- Hardenability tests shall be conducted on Grade L80-1 casing and couplings to meet the requirements of API 5CT for Grades C90-1 and T95-1.
- The frequency of hardenability tests for L80-1 shall be as per API 5CT for C90-1 and T95-1.
- Grade L80-1 shall have a minimum of 90% as-quenched martensite as per API 5CT for Grades T90-1 and T95-1.
- Grade C110 shall have a minimum of 95% as-quenched martensite as per API 5CT.

1.4.8.4 Mechanical Property Requirements

IRP Mechanical property requirements shall be as per API 5CT.

1.4.8.5 Hardness Requirements

IRP The following hardness restrictions are recommended for the sour service-rated grades of casing and couplings identified in this IRP.

Casing and coupling manufacturing specifications should stipulate that the final product be tested to confirm these restrictions are met. Hardness testing shall be performed in accordance with API 5CT.

The following table outlines the hardness requirements by grade. Hardness variation for all grades shall be as per API 5CT for grades C90-1, T95-1 and C110.

Table 9. Hardness Requirements by Grade

	J55 and K55	L80-1	C90-1	T95-1	C110
Hardness reading (max)	22.0 HRC	23.0 HRC	25.4 HRC	26.5 HRC	30.0 HRC
Hardness value (max)	22.0 HRC	22.0 HRC	25.0 HRC	25.0 HRC	30.0 HRC
Frequency: casing (one quadrant)	1/100 pipes or per heat[6]	1/100 pipes or per heat[7]	Alternate ends of every pipe	Alternate ends of every pipe	Alternate ends of every pipe
Frequency: couplings (one quadrant)	1/50 pipes or per heat[8]	1/50 pipes or per heat[9]	Both ends of every pipe	Both ends of every pipe	Both ends of every pipe

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[6] Whichever is more frequent

[7] Whichever is more frequent

[8] Whichever is more frequent

[9] Whichever is more frequent

1.4.8.6 Grain Size Requirements

IRP Grain size specifications shall be as follows:

- Grade J55 and K55 casing and couplings have no grain size requirements.
- Grain size determinations shall be conducted on Grade L80-1 casing and couplings to meet the requirements of API 5CT for Grades C90-1, T95-1 and C110 casing and couplings.
- The prior austenite grain size of grades in Grades L80-1, C90-1, T95-1 and C110 casing and couplings shall be 7 or finer.
- The frequency and method of grain size determinations shall as be per API 5CT.

1.4.8.7 Impact Toughness Testing Requirements

IRP Impact toughness testing shall be per API 5CT.

1.4.9 NACE Testing Protocols

IRP NACE Testing Protocols shall be used for all static-loaded SSC testing as per the information below.

Four static-loaded SSC test methods have been standardized by NACE International in TM0177. The four test methods are:

1. Method A – NACE Standard (Uniaxial) Tensile Test
2. Method B – NACE Standard (Three-Point) Bent-Beam Test
3. Method C – NACE Standard C- Ring Test
4. Method D – NACE Standard Double-Cantilever-Beam (DCB) Test

Two test solutions, A and B, may be used with methods A, C and D. Test Method B has its own unique solution.

Note: Test Solution A is the original NACE environment.

IRP SSC testing of casing and couplings for critical sour gas service shall be performed in Solution A.

Test Solution A is as aggressive as the most sour environment expected to be encountered in sour gas production, though may not be as aggressive as some acidizing environments if they have been contaminated with H_2S.

The principal stress on the casing is in the hoop (circumferential) direction. However, the most commonly used SSC test method, A, applies stress in the longitudinal direction. The material properties in the longitudinal direction might not be representative of those in the hoop direction. Both methods C and D more closely simulate the stress situation in casing.

Method C specimens are typically not used to test casing because of the practical difficulties encountered when handling large specimens. However, the C-ring specimen is ideal for testing the weld areas of ERW J55, K55 and, if necessary, L80-1 casing for resistance to SOHIC.

Method D specimens do not have the above size limitation and are becoming more frequently used for the qualification of higher strength casing and couplings for critical sour service. The Method D test technique is not suitable for testing J55 and K55 casing because of the difficulty in initiating sulphide stress crack growth in this low strength material.

1.4.10 Sulphide Stress Cracking Test Procedures and Acceptance Criteria

IRP The purchaser/user shall be responsible for qualification of the SSC test laboratory (i.e., to confirm they are capable of performing the SSC test method(s) correctly).

IRP The SSC test procedures and acceptance requirements shall be as outlined in the following sections.

1.4.10.1 Seamless J55 and K55 Casing and Couplings

IRP Testing Seamless J55 and K55 Casing and Couplings shall be conducted as follows:

- Use NACE TM0177 Method A in the Solution A environment.
- Use standard size specimens when wall thickness permits.
- Use at least three specimens of each sample to confirm the threshold stress.
- Use NACE TM0177 Method A pass criteria:

  1. No failure.
  2. No visual observation of surface cracks.

- Metallography shall be conducted to determine whether cracks on the gauge length are environmentally induced.
- The acceptance criteria require a minimum threshold stress of 80% or SMYS.

1.4.10.2 Electric Resistance-Welded J55 and K55 Casing

IRP Testing ERW J55 and K55 Casing shall be conducted as follows:

- The parent material shall be tested per the requirements and acceptance criteria for seamless J55 and K55 casing (as per 1.4.10.1 Seamless L55 and K55 Casing and Couplings above).
- The weld area shall be tested in accordance with NACE TM0177 Method C in the Solution A environment.
- The weld shall be located at the apex of the Method C specimen.
- Use at least three specimens of each sample to confirm the threshold stress.
- Use NACE TM0177 Method C pass criteria:

  1. No failure.
  2. No visual observation of surface cracks

- Metallography shall be conducted to determine whether cracks on the Method C specimen surface were environmentally induced.
- The acceptance criteria require a minimum threshold stress of 80% of SMYS.

1.4.10.3 L80-1, C90-1, T95-1 and C110 Casing and Couplings

IRP Testing L80-1, C90-1, T95-1 and C110 Casing and Couplings shall be conducted as follows:

- Testing shall be conducted in accordance with NACE TM0177 Method D in the Solution A environment.
- Use standard size specimens if wall thickness permits.
- Use sufficient specimens of each sample to provide a minimum of three valid test results.
- Specimens of L80-1 and C90-1 shall be fatigue pre-cracked. Specimens of T95-1 and C110 need not be pre-cracked.
- If fatigue pre-cracking of specimens is employed, the maximum stress intensity factor during pre-cracking shall not exceed 30.0 MPa√m (27.3 ksi√in) for Grades C90 and T95 or 20.7 MPa√m (18.8 ksi√in) for Grade C110.
- Specimen side arm displacements shall be as specified in API 5CT for the corresponding grades.
- Both parent material and weld area material of ERW L80-1 casing shall be tested. The DCB specimens of the weld area material shall be machined so that the weld is located at the bottom of the specimen side grooves.
- Acceptance criteria, based on standard size (B = 9.53 mm) specimens, shall be as follows for both parent and weld area material:

- For L80-1, C90-1 and T95-1 grades: An average K1SSC value of 33.0 MPa√m (30.0 ksi√inch) minimum and a single specimen K1SSC value of 29.7 MPa√m (27.0 ksi√in) minimum.
- For C110: An average value of 26.3 MPa√m (23.9 ksi√in) minimum and a single specimen K1SSC value of 23.1 MPa√m (21.0 ksi√in) minimum.

1.4.10.4 Sub-size Specimens

IRP If casing or coupling size prevents the use of standard size specimens then sub-size specimens shall be used.

IRP The manufacturer and the purchaser/user shall agree upon the acceptance criteria for sub-size specimens as per API 5CT 7.14.2 d.

1.4.10.5 Test Frequency

IRP Test frequency for all grades shall be one sample (i.e., one of the set specimens) per heat per casing or coupling size per heat treat lot, unless the manufacturer is pre-qualified.

If the manufacturer is pre-qualified (see 1.4.11 Manufacturer Prequalification and 1.4.12 SOIHC Testing for J55, K55 and ERW L80-1 Casing), subsequent testing of J55, K55 or L80-1 casing and couplings is optional.

1.4.10.6 Sample Selection

IRP Test samples selection should follow the recommendation of API 5CT Section 7.14.3.

1.4.11 Manufacturer Prequalification

IRP The manufacturer shall be pre-qualified to supply casing and couplings to the purchaser/user based on the pre-qualification of a manufacturing plan.

The prequalification method is selected by the purchaser/user.

1.4.11.1 Prequalification Method

Manufacturer prequalification may be accomplished in one of two ways.

Option 1:

- Maintenance of an SSC test database demonstrating the material's ability to meet the SSC criteria outlined in this document.
- The archived SSC test data shall be collected from materials manufactured under the same manufacturing plan.

- Testing, at a minimum, shall be as per 1.4.10 Sulphide Stress Cracking Test Procedures and Acceptance Criteria and sample requirements in 1.4.11.2 Sample Requirements.

  Note: The manufacturer is responsible for maintenance of statistical data (i.e., test procedures, test lab, test results). The purchaser is responsible for ensuring the integrity of the data through an engineering assessment. If there is a change in manufacturing process it is the responsibility of the manufacturer to update the test data to reflect the change.

Option 2: Successfully complete a SSC testing program agreed upon by both manufacturer and purchaser.

1.4.11.2 Sample Requirements

IRP Samples shall be gathered as follows:

- At least three different heats of casing and three different heats of coupling stock (for individual couplings) shall be/shall have been tested as per 1.4.10 Sulphide Stress Cracking Test Procedures and Acceptance Criteria.
- The samples of casing and couplings tested shall have been produced by the same manufacturing plan as will be used for the materials for the critical sour gas well. In particular, the chemical composition and heat treatment procedures shall be identical (within stated manufacturing tolerances).
- The samples of casing and couplings tested shall have diameters and wall thicknesses similar to or greater than those that will be used in the critical sour well.

1.4.12 SOIHC Testing for J55, K55 and ERW L80-1 Casing

IRP SOIHC Testing for J55, K55 and ERW L80-1 Casing shall be conducted based on the following:

- NACE International has not standardized a test method for SOHIC in tubular goods but both NACE Methods A and C are capable of determining the susceptibility of tubular goods to SOHIC.
- The resistance to SOHIC of J565 and K55 casing and couplings will be determined when SSC tests are conducted as per 1.4.10 Sulphide Stress Cracking Test Procedures and Acceptance Criteria. The SOHIC and SSC test acceptance criteria are identical.
- SOHIC is of particular concern in normalized and normalized and tempered materials (i.e., seamless and ERW J55 and K55).
- SOHIC is less of a concern in materials given a quench and temper heat treatment.

- If the use of ERW L80-1 casing is planned, an engineering assessment shall determine whether testing for resistance to SOHIC is necessary.

1.4.13 HIC Test Requirements for J55 and K55 Casing

1.4.13.1 Testing Protocols

IRP J55 and K55 casing and couplings shall be HIC tested using one of the two protocols below.

Protocol 1: Testing of all casing and couplings as outlined in 1.4.13.2 Test Requirements. Test frequency shall be one sample (i.e., one set of specimens) per heat, per casing size, per heat treat lot.

Protocol 2: Pre-qualification of the manufacturer and subsequent testing of selected casing and couplings at the discretion of the purchaser/user. The protocol used for manufacturer pre-qualification shall be the same as that given in section 1.4.11 Manufacturer Prequalification. The testing procedures and acceptance criteria shall be as outlined in 1.4.13.2 Test Requirements.

1.4.13.2 Test Requirements

IRP J55 and K55 Casing testing shall be conducted as follows:

- HIC tests shall be conducted in accordance with NACE TM0284 for J55 and K55 casing and couplings.
- The test environment shall be Solution A. It is mandatory to continuously bubble H_2S through the test solution for the duration of the test (after the initial saturation period) at the same rate as specified in NACE TM0177 Method A.
- It is mandatory to lightly etch the metallographic cross-sections of the tested specimens before examination for the presence of HIC damage.
- Acceptance criteria shall be a sample average Crack Length Ratio (CLR) of 5.0% maximum and a sample average Crack Thickness Ratio (CTR) of 1.5% maximum.
- No single cross section shall have a CLR which exceeds 25% or a CTR which exceeds 10%.

1.4.14 Pressure Test Requirements for ERW Casing

IRP All ERW casing must be hydro-tested to 100% burst rating prior to manufacturer's inspection.

1.4.15 Casing Identification

IRP Casing materials shall be dual marked with the API monogram and the manufacturer's proprietary grade identification/name.

1.4.16 Inspection

1.4.16.1 Compliant Casing

IRP The following inspections to detect defects shall be performed on new casing and coupling stock (manufactured to conform to this IRP) as per API 5CT:

Table 10. Inspections by Grade

	J55 and K55	L80-1	C90-1	T95-1	C110
Casing	SR1 is acceptable SR2 is recommended	SR2	SR2	SR2	SR2
Coupling Stock	SR14	SR14	SR14	SR14	SR14

IRP Inspections shall be as follows:

- Conduct special end area (SEA) inspection on every pipe length unless the manufacturer crops the pipe ends not covered by the automated pipe body inspection equipment.
- Conduct visual and magnetic particle inspection (MPI) of both the internal and external surfaces of the pipe ends to detect the presence of transverse and longitudinal defects.
- Overlap the SEA inspection and automated pipe body inspection by a minimum of 50 mm.
- Visually inspect exposed threads for damage. Consult API RP 5A5 Section 4.4 for details.

1.4.16.2 Non-Compliant Casing

IRP New casing and couplings not originally made in conformance with this IRP shall be acceptable provided they pass the inspection and testing requirements noted below.

- The casing and couplings shall be tested to confirm resistance to SSC, SOHIC and HIC per the requirements of this IRP. This requirement applies to J55, K55, L80-1, C90-1, T95-1 and C110.
- SEA inspection shall be conducted on every joint of casing.
- For grades J55, K55 and L80-1, random surface hardness tests shall be conducted on one pipe in fifty and on all couplings unless mill hardness testing records are available. Hardness tests shall be conducted on both pipe ends.

- For J55 and K55, a hardness reading greater than 22.0 HRC shall be cause for rejection of the pipe or coupling and increased testing frequency of the remaining pipe.
- For L80-1, a hardness reading greater than 23.0 HRC shall be cause for rejection or prove-up of the pipe or coupling and increased testing frequency of the remaining pipe.
  - If any single hardness reading exceeds 23.0 HRC, two additional readings shall be taken in the same area to prove-up the pipe or coupling.
  - The average of all the readings shall not exceed 22.0 HRC for the pipe or coupling to be acceptable.
  - The testing frequency shall be increased to every pipe.
- Every joint must be traceable back to mill certificates documenting, at minimum, yield and tensile strength and chemistry.
- Use of new, non-compliant grades of C90-1, T95-1 and C110 casing and couplings is not recommended.

1.4.17 Intermediate Casing

IRP Intermediate casing must meet the design specifications as outlined in this IRP.

IRP Intermediate casing shall be set at a point before the cumulative release rate becomes critical.

Note: AER Directive 036: Drilling Blowout Prevention Requirements and Procedures requires intermediate casing be set at 3600 m. AER approval is required for any variance.

Intermediate casing may not be required depending on the combination of the well type criteria described in section 1.1.3 Well Types. The exemption from setting intermediate casing must be approved by the appropriate regulatory agency and the information outlined in 1.1.3 Well Types included in the project plan.

If the exemption is approved, the following conditions must be met:

- The wellbore integrity, including the casing and open-hole sections, must be evaluated by an open-hole integrity test prior to penetrating the critical sour zone and must be found capable of holding anticipated formation pressures before continuing to drill without intermediate casing.
- The surface casing grade must be suitable for sour service (i.e., meet the specifications of this IRP).
- The kick tolerance calculations must demonstrate the surface casing and formation leak-off at the casing shoe can withstand a three cubic metre gas kick.

1.4.18 Re-Entry Wells

IRP A casing evaluation must be conducted to evaluate casing thickness (due to wear and corrosion) for re-entry wells and the design of the existing casing checked against the casing design recommendations outlined in IRP 1.

IRP Re-Entry well casing must meet the design specifications as outlined in this IRP with the addition of the following:

- A collapse assessment is required from surface to 150 m below the confirmed cement top or surface to 1000 m, whichever is greater.
- A tensile assessment is required from surface to 150 m below the confirmed cement top or surface to 1000 m, whichever is greater.
- For re-entry wells the burst rating of the casing is calculated using the following formula (as per API TR 5C3):

Equation 1. Burst Rating for Re-Entry Well Casing

$$\text{Burst Rating} = (1\text{-}A)\ x\ 2 f_{ymn}\ x\ (t_{logmin}/D)$$

Where:

A = accuracy of wall thickness log
f_{ymn} = specified minimum yield strength
t_{logmin} = minimum wall thickness from log
D = casing OD

- A casing inspection log must be run and the casing design ratings must be calculated based on these data.
- Specific documentation of suitable metallurgy or evidence of SSC resistance is required in order to qualify a casing which would not currently be considered for sour service.
- Metallurgy can be verified with mill certification or sample and testing of the top joint of a verified homogeneous string of casing.
- An engineering assessment must be performed to ensure the suitability of the existing casing's metallurgy and compliance with casing specifications listed in Table 8 Chemical Composition Requirements.
- The casing must be pressure tested to 67% of current formation pressure prior to drilling into the critical sour zone.

1.5 Blowout Preventer Stack

1.5.1 Scope

This chapter addresses all equipment which forms an integral part of the blowout preventer (BOP) stack, equipment directly attached to the stack (from below the rotary table to the casing bowl) and all BOP control systems.

1.5.2 Design Considerations

In the selection of preferred BOP stack arrangements, it is necessary to accept the fact that equipment can fail and to design a redundant system to reduce the effect of a failure. The design should take into account the probability of a given component failing or a given situation occurring. The safety of the on-site personnel is the most important factor in any design.

1.5.3 Codes and Standards

The following codes and standards are referenced in this section:

- API 6A Specification for Wellhead and Christmas Tree Equipment, Twentieth Edition. 2013.
- API 16C (R2010) Choke and Kill System. 2010.
- API STD 53 Blowout Prevention Equipment for Drilling Wells, Fourth Edition. 2012.
- API RP 5C1 (R2010) Recommended Practice for Care and use of Casing and Tubing, 18th Edition. 1999.
- API RP 5A3 Recommended Practice on Thread Compounds, Tubing, Line Pipe, and Drill Stem Elements, Third Edition (ISO 13678:2009 Identical Adoption). 2009.
- ASME Boiler and Pressure Vessel Code – 2013 Edition, Section IX Welding and Brazing Qualifications.
- CAODC RP 6.0 - Drilling Blowout Preventer Inspection and Certification, August 2012.
- NACE MR0175/ISO 15156 Materials for use in H_2S-containing environments in oil and gas production, 2009 Edition.

1.5.4 Configuration

1.5.4.1 Configuration Options

IRP Minimum BOP stack components shall consist of an annular preventer, two spools and three ram preventers.

The use of integral studded or integral flanged side outlets on the lower ram preventer in place of the lower drilling spool is an acceptable exception but only if engineered by the original ram body manufacturer and installed during initial manufacturing of the ram. This BOP configuration should only be used where sufficient surface/intermediate casing is in place to contain the maximum anticipated reservoir pressure. This will minimize the need to conduct well control operations through the side outlets.

IRP The configuration for the BOP stack shall conform to Figure 1, 2 or 3 below.

Configuration 3 (Figure 3) should only be used where sufficient surface/intermediate casing is in place to contain the maximum anticipated reservoir pressure at the surface because the closing of the lower pipe ram will result in the inability to bleed off pressure from the wellbore. Otherwise use configuration 1 (Figure 1) or 2 (Figure 2).

Figures 1, 2, 3 and 4 are taken from AER [Directive 036: Drilling Blowout Prevention Requirements and Procedures].

Figure 1. BOP Stack Configuration 1

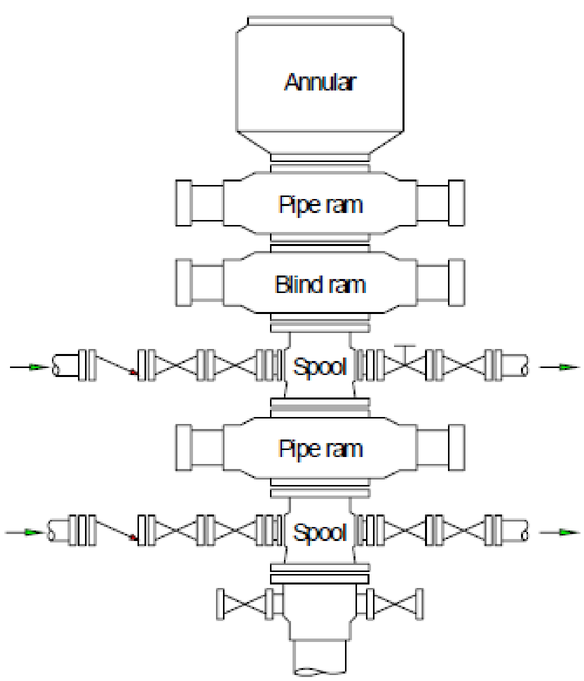


Figure 2. BOP Stack Configuration 2

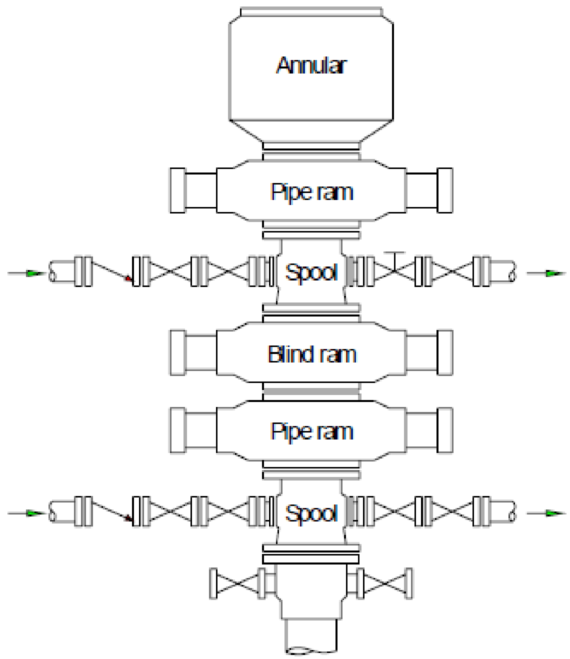
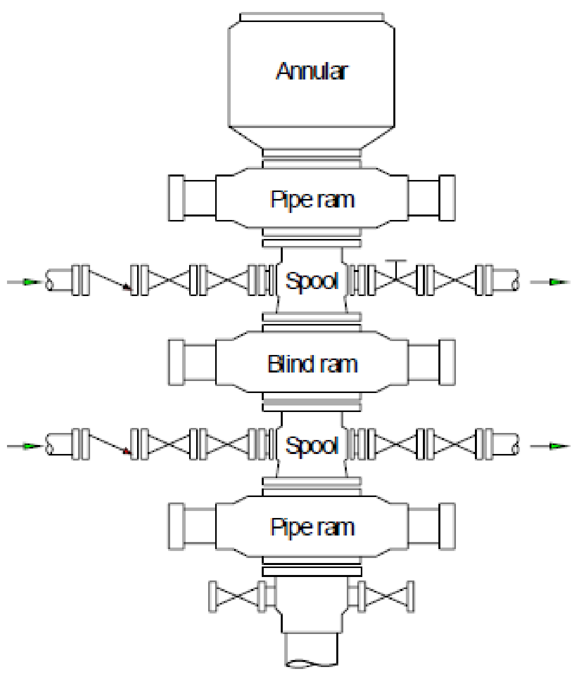


Figure 3. BOP Stack Configuration 3



Note: Configurations 2 and 3 could be improved by using a ram blanking tool (Figure 5) when the drill string is out of the hole to allow the top ram to function as a blind ram.

Figure 4. Symbols

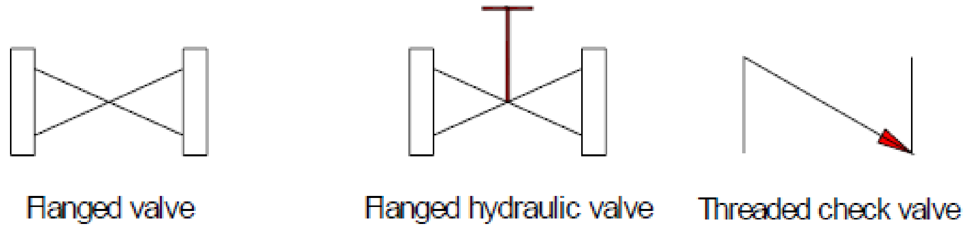
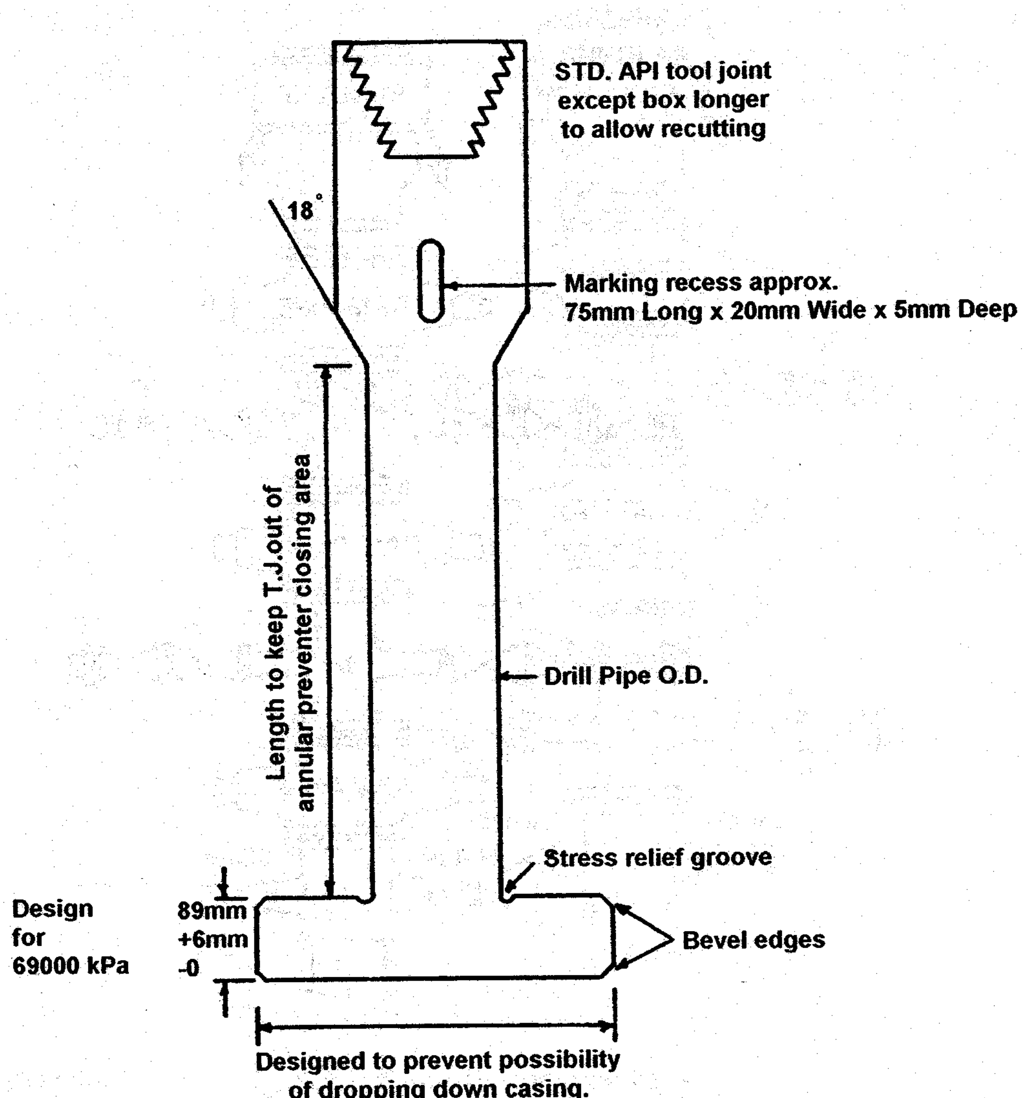


Figure 5. BOP Ram Blanking Tool



1.5.4.2 Pipe Ram Size

IRP The pipe rams should be the correct size for the drill string used.

For drill strings with two pipe sizes, the top pipe ram should be sized for the larger pipe size and the lower pipe ram should be a variable bore ram sized for both pipe sizes. The top rams could also be variable bore. If any rams are changed (e.g., casing rams) they must be pressure tested.

1.5.5 Shear Blind Rams

1.5.5.1 Introduction

Shear blind rams replace the blind rams in the BOP stack. They are designed to close and seal the open hole as normal blind rams and can cut (shear) drill pipe, tools, wireline, etc. and allow the objects to drop out of the way of the rams before sealing the open hole.

Shear blind rams would only be used if other well control equipment has failed, likely in the following circumstances:

- An inside blowout and leak in surface equipment.
- A pipe ram or annular leak.
- When the drill string is out of the hole (i.e., used as blind rams).

Shear blind rams provide a final opportunity to regain control of a well and therefore could prevent ignition (see 1.3.4 Emergency Response Plan). However, if inadvertently or prematurely activated, well control operations will be significantly hampered because once the drill pipe is sheared the primary well control capability (i.e., circulation of weighted fluid) may not be immediately available.

1.5.5.2 Usage

IRP Shear blind rams must be used for any critical sour well where the calculated emergency planning zone intersects the boundaries of an urban centre or contains more than 100 occupied dwellings.

IRP Shear blind rams should be used for most other critical sour wells unless the well is low complexity, low impact and/or a simple ERP well (see 1.1.3 Well Types).

IRP Whenever blind shear rams are not installed, the operator should evaluate running a drill string float (internal BOP) (see 1.8.10 Downhole Floats).

1.5.5.3 Design Requirements

IRP Shear blind ram design should be as follows:

- All shear blind ram components, including the shearing member(s) and internal bolting, should meet the material standards as outlined in 1.5.8 Metallic Materials for Sour Service and 1.5.9 Non-Metallic Materials Requirements for Sour Service.
- Shear blind rams replace the conventional blind ram in the preferred configurations (see 1.5.4 Configuration).

Note: There are no technical or operational advantages to having the shear blind rams as an addition to the stack components illustrated. The shear blind ram performs the same function, with similar reliability, as the blind ram when the drill string is out of the hole. For additional information consult the OEM.

- Casing design and setting depth should be reviewed to ensure the well can effectively be shut in (see 1.4.17 Intermediate Casing).

1.5.6 Auxiliary Equipment

1.5.6.1 Choke Line Usage

The choke line is the flow line off the BOP stack used to control flow during the kill operation.

IRP The choke line should be used as follows:

1. The top choke line should be used as the primary line and the bottom choke line should only be used as a backup system to control flow in the well during a kill operation.
2. The bottom secondary spool should only be used as an emergency line to control pressure during a component failure when the top primary spool is inoperative. Unless absolutely necessary, this bottom secondary spool is not to be used to kill the well. Instead, the failure should be repaired and kill procedure resumed.

1.5.6.2 Wing Valves vs. Drilling Spool

IRP Wing valves on the casing bowl or on the intermediate spool should not be considered acceptable substitutes for a drilling spool.

1.5.6.3 Hydraulic Control Remote Valve

IRP The position of the Hydraulic Control Remote (HCR) valve should be at the contractor’s and operator’s discretion. The configurations outlined in 1.5.4 Configuration are recommended arrangements.

Special cases are always discussed when deciding whether the HCR valve should be located inside the manual valve. The inside location of the HCR offers advantages under special circumstances. Since the distance between the stack and HCR is shortened, the potential for plugging and freezing is reduced. This advantage becomes more important when high viscosity weighted drilling fluids are being used and in the case where mud rheological properties are affected by an H_2S influx. Alternatively, the outside position enables workers to isolate the well when servicing the HCR valve.

1.5.6.4 Handwheels

IRP Handwheels, in a readily accessible position, should be provided for each manually locking ram.

When using variable bore rams check the manufacturer's specifications closely. Some systems will not lock in two positions.

1.5.6.5 Drilling Through Equipment

IRP All drilling through equipment above the top flange of the annular preventer should be designed and constructed to allow emergency access to the topmost pressure rated flange on the annular.

Drilling through equipment refers to the following:

- Rotary tables
- Flow nipples
- Automatic pipe wiping devices
- Rotary drilling heads

Auxiliary equipment installed above the annular preventer top and rig floor base allows potential interference with non-routine well control situations where access to the topmost pressure rated flange on the annular, through the rotary table, is required (e.g., installation of snubbing units).

The drilling through equipment should either

1. be removable with the drill pipe still in place (i.e., split in two or stripped over the drill pipe) or
2. open to a sufficient size to permit the installation of additional well control equipment on top of the BOP stack (e.g., an adaptor/spacer spool of the same pressure rating as the BOP stack).

Typical rotary table sizes may restrict the BOP stack. For example, if a 346 mm x 34,000 kPa BOP stack is used, a 699 mm rotary table would be required unless the rotary can be split or stripped over the drill pipe.

1.5.7 Mechanical Specifications

1.5.7.1 Pressure Rating

The pressure rating of a BOP stack is equal to the API pressure rating of the weakest stack component. BOP stack components include casing bowls, valves, preventers, flanges and any other equipment directly attached to the stack or casing bowl that would experience stack pressure (e.g., surface casing if intermediate casing is not required).

IRP BOP Stack pressure rating requirements shall be as per the appropriate regulatory body.

1.5.7.2 Casing Bowls

IRP Welded casing bowls shall be welded in accordance with an acceptable welding procedure developed from API 6A, NACE MT0175/ISO 15156 and ASME Boiler and Pressure Vessel Code Section IX.

IRP Threaded casing bowls shall be manufactured in accordance with API 6A, utilize make-up procedures and torque in accordance with API RP5C1 and utilize a thread compound in accordance with API RP5A3.

IRP Casing bowl outlets should be flanged for service on wells that have a stack pressure rating of 21,000 kPa or greater as per API STD 53.

1.5.8 Metallic Materials for Sour Service

1.5.8.1 Metallic Material Requirements

This section applies to all pressure-containing components within the BOP stack with the potential to be exposed to H_2S including:

- Attached valves
- Pressure gauges and sensors
- Choke lines through to the outside valves of the choke manifold

IRP All pressure-containing components within the BOP stack with the potential to be exposed to H_2S shall be constructed of materials that meet NACE MR0175/ISO 15156.

IRP Components should be marked in a manner that shows their suitability for sour service as per NACE MR0175/ISO 15156. Identification stamping procedures as detailed in NACE MR0175/ISO 15156 Section 5.4 should be followed.

IRP Proof of certification must be available and produced upon request.

1.5.8.2 Bolting Requirements

IRP External bolt selection should be carefully considered relative to the potential for H_2S contact.

Subcomponents not normally exposed to hydrogen sulphide, such as external studs and nuts, are not required to meet NACE MR0175/ISO 15156 (**Note:** API STD 53 does not permit this exception).

Specific rig configuration should be considered with respect to BOP ventilation, coverings, etc. to determine if the studs and nuts could be exposed to H_2S.

There are three options for external bolt selection (as per API 6A):

- Use ASTM B7 and L7 for bolting not directly exposed to H_2S. This will meet sour service conditions of NACE MR0175/ISO 15156 and provides full API pressure rating but could result in SSC susceptibility.
- Use ASTM B7M and L7M for bolting directly exposed to H_2S. This will meet sour service conditions of NACE MR0175/ISO 15156 and provide SSC resistance. **Note:** Previous editions of API 6A permitted some sizes of B7M and L7M if the pressure rating of the BOP stack was reduced. Those sizes are no longer permitted and Grade 660 bolting must be used. Those sizes are:
    - 5000 psi (34.5 MPa) 13-5/8 and larger
    - 10,000 psi (69 MPa) 4-1/16 and larger
    - 15,000 psi (109 MPa) 2-1/16 to 4-1/16 and 7-1/16
- Use ASTM 453 Grade 660 for bolting directly exposed to H_2S. These bolting materials are SSC resistant and of a strength comparable to B7 bolting.

Bolting identification and control during rig moves requires special attention to ensure all bolts are replaced in the correct locations.

1.5.9 Non-Metallic Materials for Sour Service

This section applies to BOP stack components constructed from non-metallic components with the potential to be exposed to H_2S including:

- Annular preventer and ram rubbers
- Bonnet and door seals
- Packing for BOP secondary seals

IRP Non-metallic materials for sour service should conform to API STD 53 section 19.6.

As elastomer technology continues to evolve, consultation with the original equipment supplier as to the most suitable elastomers is recommended. Elastomers tend to be less tolerant than metallic materials due to the range of drilling environments encountered.

Detailed fluid properties and the range of operating conditions expected at the well should be addressed in the elastomer/drilling fluid selection process.

1.5.10 Transportation, Rigging Up and Maintenance

IRP The following factors should be considered during BOP transportation, rigging up and maintenance:

- Avoid cold work to prevent hardening of equipment components.
- Avoid any hammering action which could deform the stack component material.
- Follow manufacturer specifications for bolt up torque.
- Avoid marking of components with die stamps except where permitted by API 6A section 8.
- Avoid welding brace supports to BOP materials.
- Follow practices outlined in 1.9 Welding for any welding for component fabrication.

IRP Material control for replacement parts for the BOP stack should have specifications and quality control equivalent to the original equipment.

1.5.11 Control Systems

1.5.11.1 Hydraulic Pump Requirements

IRP Two separate sources of hydraulic pressure should be provided to recharge the accumulators.

Hydraulic pump requirements should consider the following:

- For low complexity, low impact and simple ERP wells, one source can be considered (see 1.1.3 Well Types).
- The nitrogen reserve system is not considered the second source of hydraulic pressure.
- The pumps should have a working pressure equal to that of the accumulator system as per API STD 53 section 12.4.3.
- One of these units should start automatically when the accumulator pressure drops below 90% of its operating pressure as per API STD 53 section 12.4.5.
- One hydraulic power source should, without the accumulator, be capable of

1. closing the annular preventer on drill pipe,
2. opening the HRC valve and
3. obtaining 1400 kPa above the accumulator pre-charge pressure within five minutes.

1.5.11.2 BOP Master Control Station Location

IRP The BOP master control shall be installed at a location remote from the rig floor.

IRP The master control station should be located at ground level and remote from the rig floor, a minimum of 15 m from the well centre.

Locating the master BOP control station adjacent to the accumulators, or at an alternate ground level location, is desirable when drilling a critical sour well for the following reasons:

- The BOPs can be activated in the event of a fire on the rig floor or in the substructure.
- The BOPs can be activated in the event of a mechanical failure or interference with the BOP control station on the rig floor.
- There is greater potential for successfully rigging up an auxiliary BOP control system, specifically power and control lines, should the original systems be rendered inoperative.
- There is individual control and return lines for each BOP element and HCR actuator.

1.5.11.3 Minimum Accumulator Sizing

1.5.11.3.1 Accumulator System

IRP The accumulator system design shall be as follows:

- The accumulator system shall be sized such that, when charted to its operating pressure and with the recharge pump off, there is sufficient volume to open the HCR, close the annular preventer on the drill pipe and close, open and close one ram preventer.
- The final accumulator pressure shall not be less than 8,400 kPa.
- The accumulator must have sufficient volume to close the annular preventer on an open hole.
- Where blind shear rams are run, the accumulator size must be increased or a separate accumulator system installed to provide sufficient volume and pressure to shear the drill pipe.

- The following accumulator system recommendations should be considered:
  - The hydraulic manifold should be equipped with a full opening valve and provision for tie in of an auxiliary source of closing fluid as per API STD 53 section 13.9.3a.
  - Provide for the isolation of the accumulators and pumps from the BOP controls to allow isolation of both pump systems and accumulators from the manifold and annular control circuits to permit safe maintenance and repairs as per API STD 53 section 13.9.3b.
  - Provide for the isolation of accumulator banks into at least two sections.
  - If blind shear rams are included, the accumulator must be equipped with a hi-low pressure bypass valve to allow full accumulator pressure to the shear blind rams. This bypass valve must be identified and well control drills must include crew training in proper use of the valve.

1.5.11.3.2 Hydraulic Fluid

IRP The fluid used in the hydraulic system should have a minimum pour point of -50°C and should be of a type approved by the BOP manufacturer.

1.5.11.3.3 Nitrogen Reserve System

IRP The nitrogen reserve system design should be as follows:

- The nitrogen reserve system should be sized to
  1. open the HCR valve,
  2. close both the annular preventer and one ram preventer and
  3. maintain at least 14,500 kPa over the manifold pre-charge pressure.
- The system should provide for isolation of the nitrogen supply from the accumulator system.
- If shear rams are included, a separate nitrogen booster system should be capable of meeting pressure and volume requirements to shear the tubulars in use.

1.5.12 Inspection and Servicing Requirements

1.5.12.1 Service Timing

IRP All blowout preventer systems, including spools, must be shop serviced, shop tested and certified for use every three years.

IRP Any time a BOP stack is subjected to an uncontrolled flow of reservoir fluids, the stack should be shop serviced and tested prior to that stack going back into service as per AER Directive 36: Drilling Blowout Prevention Requirements and Procedures.

After a kick or a well control operation, shop servicing may be carried out at contractor or operator discretion.

1.5.12.2 Shop Servicing

IRP All repairs and replacements shall meet the same requirements as the original preventer as per NACE MR 0175/ISO 15156 and API RP 5.

IRP Shop servicing should be as per CAODC RP 6.0 for Level IV Inspections.

1.5.12.3 Pressure Testing

IRP A pressure test shall be completed after reassembly. The following requirements apply:

- Three bore pressure tests are required per component as follows:
    - One low pressure (1,400 kPa.).
    - Two at the pressure rating of the BOP.
- Pressure testing of all hydraulics is to be done in both the open and closed position to a minimum pressure of 10,500 kPa or manufacturer's specification.
- All pressure tests are to be conducted for a minimum of 15 minutes.
- The BOP pressure testing frequency during drilling is outlined in 1.14.3.1 BOP Pressure Testing.

1.5.12.4 Hardness Testing

IRP Harness testing shall be conducted on any welding repairs as per 1.9 Welding.

1.5.12.5 Documentation

IRP The following testing documentation should be kept:

- A BOP shop testing and shop servicing form completed by a qualified technical expert, as defined in AER Directive 36: Drilling Blowout Prevention and Procedures, and stating the date of the service test.
- A certification indicating the date shop testing was last performed should be displayed in a prominent position in the dog house.

- A copy of the complete shop servicing report should be kept on file by the drilling contractor.

1.6 Choke Manifold

1.6.1 Scope

This chapter addresses the choke manifold, the choke lines and the kill lines and their metallurgical requirements.

> **Note:** The choke lines discussed in this chapter refer to the line between all BOP stack valves and the choke manifold. The kill line refers to the section between the mud pump manifold and the BOP stack valves.

The equipment addresses the following:

- Location
- Housing
- Configuration
- Auxiliary equipment

The metallurgy requirements cover the following:

- Existing equipment
- Use of flexible hose
- Fabrication and certification of new installations
- Documentation of qualified manifolds

1.6.2 Codes and Standards

The following codes and standards are referenced in this section:

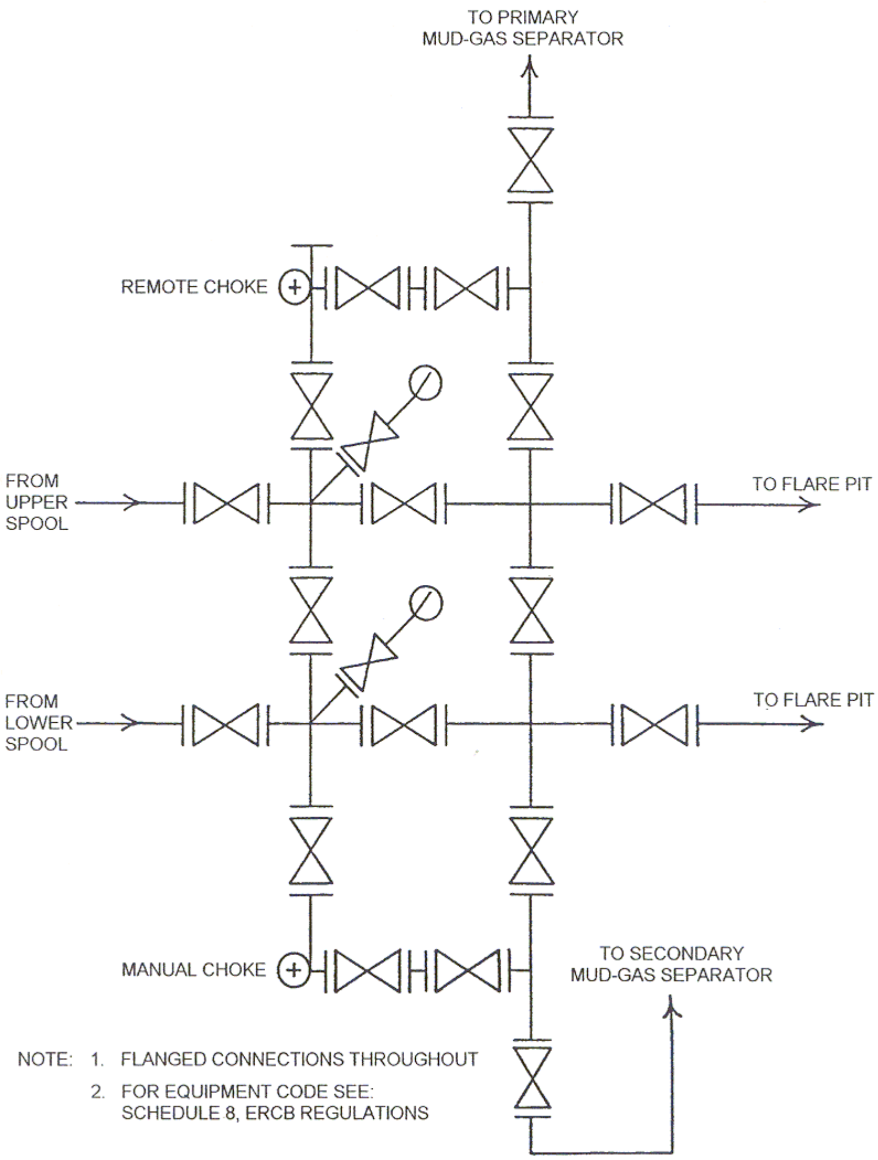
- API Spec 5CT Specification for Casing and Tubing, Ninth Edition. 2011.
- API 6A Specification for Wellhead and Christmas Tree Equipment, Twentieth Edition. 2013.
- API 16C (R2010) Choke and Kill System. 2010.
- CAODC RP1.0 Mast Inspection for Drilling Rigs, July 2001.
- NACE MR0175/ISO 15156 Materials for use in H2S-containing environments in oil and gas production, 2009 Edition.

1.6.3 Design Specifications

IRP The manifold and piping shall provide complete redundancy from the BOP stack, through the manifold, to the mud-gas separators and finally to the flare pit. Figure 6 outlines the recommended manifold layout.

Note: Where only one mud-gas separator is being used, redundancy from the manifold to the mud-gas separator and from the mud-gas separator to the flare pit is not required.

Figure 6. Choke Manifold Layout



IRP The choke manifold design shall be as follows:

- A separate bleed-off line shall be used from each spool to a separate manifold wing (side) and must be equipped with a separate casing pressure gauge.
- A remote, hydraulic operated, non-rubber sleeve choke shall be used on the primary manifold wing (upper BOP spool) and a manual operated choke on the secondary manifold wing (lower BOP spool).
- Each choke should be capable of being routed through either wing of the control manifold.
- Equipment for manifold systems should conform to API 6A.
- All components and materials including valves, chokes, lines and fittings should comply with NACE MR0175/ISO 15156.
- Lines should be kept as straight as possible leading up to the preferred horizontal manifold configuration.
- Fitting (tee and cross) and pipe materials should be consistent. Internal diameters (ID) of fittings should be matched to the pipe ID.
- All welds should be 100% radiographed after being stress relieved and documented as described in 1.9 Welding.
- During winter operations the manifold and related piping should be filled with water-soluble antifreeze compatible with the manifold components. Diesel is not recommended for use as antifreeze because diesel/drilling fluid segregation may allow water-based fluid accumulation and line blockage.

1.6.4 Valve and Choke Specifications

IRP The valves and chokes should be as follows:

- Valves should be full bore gate valves with an opening equal to or slightly greater than the manifold piping ID.
- Valve bodies and bonnets should be constructed of forged or cast 65K or 75K material as per API 6A.
- Valves with integral flanges are preferred and are to be compatible with the piping flanges.
- Valves should be furnished with secured handwheels indicating the direction the valve opens as per API 6A.
- If the valve has a preferred pressure side it should be clearly marked.
- Adjustable choke specifications should identify the fully open and fully closed positions on the choke body and on the actuator (if equipped).
- Recommended choke body material is API 6A 60K.
- Inlet and outlet flanges should meet or exceed manifold pressure rating.

1.6.5 Flange, Ring Gasket and Bolting Specifications

IRP Flanges, ring gaskets and bolting should be as follows:

- Flanges should be utilized throughout with no interconnection between API and ANSI types.
- R or RX rings should be used on API 6B flanges. BX rings should be used on API 6BX flanges. Ring Types BX 150 through BX 160 should not be reused.
- Gasket materials should be as per API 6A.
- ASTM A193 B7M, ASTM A320 L7M or Grade 660 material shall be used (as appropriate) for bolting directly exposed to H_2S. Not all flange sizes, because of pressure ratings, can accommodate B7M or L7M bolting. For bolting not directly exposed to H_2S, ASTM A193 Grade B7 or ASTM A320 Grade L7 can be used in addition to those listed above.
- ASTM A194 Grade 2HM or 7M nuts are recommended on jacketed flanges. Hardness should be limited to HRC 22 when utilizing proprietary grade 2HX nuts.
- The data in Table 11 below should be utilized for specifying API Pipe and Flange combinations.

Table 11. Recommended API Flanged Choke and Kill Line

Flange						
AER BOP Class	**Type**	**Material**	**Normal Size (In.)**	**Actual ID (mm)**	**Actual OD (mm)**	**Press Rating (MPa)**
Class II	API 6B	API36 / 45K	2-1/16	52.50	60.5	13.8
	API 6B	API36 / 45K	3-1/8	7.93	88.9	13.8
Class III	API 6B	API36 / 45K	2-1/16	52.50	60.5	13.8
	API 6B	API36 / 45K	3-1/8	77.93	88.9	13.8
Class IV	API 6B	API36 / 45K	2-1/16	49.25	60.5	20.7
	API 6B	API36 / 45K	3-1/8	73.66	88.9	20.7
Class V	API 6B	API36 / 45K	3-1/8	66.65	88.9	34.5
Class VI	API6BX	API60K	3-1/16	77.78	110.3	69.0

Table 12. Recommended Pipe

Pipe							
Type & Grade	**Schedule**	**Nominal Pipe Size (Inches)**	**Linear Density (kg/m)**	**Actual ID (mm)**	**Actual OD (mm)**	**Wall Thk. (mm)[10]**	**Calc. Press Rating (MPa)**
API X46	STD (40)	2	5.44	52.50	60.3	3.91	35.99
API X46	XS (80)	2	7.48	49.25	60.3	5.54	50.95
API X46	STD (40)	3	11.29	77.93	88.9	5.49	34.25
API X46	XS (80)	3	15.27	73.66	88.9	7.62	47.57
ASTM A106 Grade B	160	3	21.35	66.65	88.9	11.13	52.85
ASTM A106 Grade C	160	3	21.35	66.65	88.9	11.13	60.40
API X56	XXS	3[11]	27.68	58.42	88.9	15.24	115.83
ASTM A106 Grade B	XXS	4	41.03	80.06	114.3	17.12	63.25
ASTM A106 Schedule XXH Grade C	XXS	4	41.03	80.06	114.3	17.12	72.28

A minimum wall thickness should be calculated based on operating pressure.

Minimum nominal diameter should be as per AER Directive 36: Drilling Blowout Prevention Requirements and Procedures Appendix 3: Blowout Preventer Systems.

[10] Wall Thickness (mm)

[11] Requires weldneck flange transition piece to match flange and pipe boxes

Calculated Pressure Rating (MPa) is based on API Internal Yield Pressure for Pipe as per API 5C3.

Equation 2. Pressure Rating

$$P = 0.875 \left[\frac{2\text{Ypt}}{\text{D}}\right]$$

Where:

- P = Minimum internal yield pressure in psi rounded to nearest 10 psi (or MPa)
- Yp = Minimum specified yield strength in psi as given in API 5CT/ISO 11960 (or MPa)
- t = Wall thickness in inches (or mm)
- D = Nominal Outside diameter in inches (or mm)
- Internal yield pressures are calculated by using tabulated values of diameter and thickness to obtain a t/D ratio value rounded to the nearest 0.000001.

1.6.6 Flexible Steel Hose Specifications

IRP Flexible steel hoses may be used to interconnect rigid steel lines to BOP spool outlets or other rigid steel lines.

Note: Full length flexible steel hoses or kill lines are permitted but not universally recommended because they may be subject to external damage.

IRP Flexible steel hoses should meet all of the specifications and criteria outlined below.

1.6.6.1 Pressure Integrity

Flexible hose assemblies should possess a pressure integrity rating equal to working pressure for any temperature between 90°C and -40°C. This rating should always equal or exceed the rating of the BOP stack.

1.6.6.2 Internal Diameter

The internal diameter of flexible hoses should be consistent throughout and equal to the internal diameter of the pipe.

1.6.6.3 Flanges

Flanges compatible with BOP and choke manifold connections should be used for end connectors.

1.6.6.4 Materials

A representative sample of the flexible steel hose assembly should demonstrate the capability to withstand 25% H_2S in water-saturated methane at 90% for a minimum of 24 hours at rated working pressure without leaking.

All metal components which may be exposed to sour fluid, including connectors, should meet NACE MR0175/ISO 15156.

The material used in the internal bore should exhibit a high degree of abrasion resistance and not be susceptible to degradation by exposure to any of the following fluids:

- Fresh or salt water
- #1 or #2 diesel fuel with aniline points over 60°C
- Water based, oil based or mineral oil based drilling fluids
- Sweet or sour gas or condensate
- CO_2 or water glycol solution

1.6.6.5 Anchoring and Bends

All flexible hoses should be supported and anchored in accordance with manufacturer recommendations.

Support and anchoring devices should not be allowed to produce localized bends.

Any bends should occur at a point remote from end fittings and should contain a bend radius safely in excess of the manufacturer specified minimum. Bends with a radius 1.5 times greater than specified minimums are preferred.

1.6.6.6 Heat Tracing

Heat trace temperatures should be controlled when winterizing hoses to avoid thermal degradation of non-metallic flexible hose components.

1.6.6.7 Testing and Documentation

New hose assemblies should pass a hydrostatic test at 1.5 times the working pressure rating for a minimum of five minutes. The manufacturer should be asked to provide documentation to verify successful compliance with this test.

Used hose assemblies should be pressure tested at least every three years to the rated working pressure for 10 minutes using a low viscosity, solids-free fluid. For standard stack and manifold pressure tests, the flexible hose should be pressure tested to the BOP stack rating.

Suitable types of flexible hose should demonstrate the capability to withstand 450°C of direct flame exposure for a minimum of 15 minutes at 10.4 MPa applied pressure.

Pressure testing should coincide with frequency for shop servicing of BOPs (as per 1.5.12 Inspection and Servicing Requirements). Periodic shop inspections are considered quite important to evaluate the detailed condition of flexible hose because field inspections are difficult. Field inspections may not be straightforward because of the following:

- Pipe wall condition is difficult to assess using conventional inspections.
- Areas of erosion are difficult to locate due to a variable bend location from well to well.
- Ultrasonic thickness testing is somewhat meaningless for flexible hose.

Permanent markings on the flexible hose assembly should be visible and include the following:

- Working, test and burst pressure ratings
- Manufacturer
- Date of manufacture
- Minimum bend radius

1.6.7 Pressure Gauges

IRP The manufacturer, style and physical size of pressure gauges and sensors should be left to contractor/operator discretion.

For greatest accuracy at low pressures, diaphragm sensors are preferred to supply signal to the low pressure standpipe, casing and compound mud gauges.

1.6.7.1 Standpipe Gauges

IRP Standpipe pressure gauges should be as follows.

Existing standpipe gauges can be utilized on critical wells provided they do not significantly exceed the BOP or manifold rating.

Except in the cases of Class I and II rigs, the capability to install a low pressure gauge (7,000 kPa) to supplement the standpipe gauge is recommended. This low pressure gauge should be installed in parallel with the existing standpipe gauge and must be protected by either a pressure limiting device or a needle valve rated at least as high as the BOP and manifold.

1.6.7.2 Casing Gauges

IRP Casing pressure gauges should be as follows:

- The capability to install a low pressure (7,000 kPa) gauge to supplement the regular casing pressure gauge is recommended. This low pressure gauge should be installed in parallel with the existing casing gauge and must be protected by either a pressure limiting device or needle valve rated at least as high as the BOP and manifold.
- Recommended casing pressure gauge range is approximately 125% to 167% of the maximum pressure that may be encountered and at least 100% of the BOP and manifold working pressure rating.
- The use of excessively higher casing pressure range gauges than required for the BOP pressure rating should be avoided. Examples of such ranges would be 70,000 or 105,000 kPa gauges on 21,000 or 35,000 kPa manifolds.
- Casing pressure gauges should be checked for proper operation

  1. monthly (by pressurizing the choke line side of the sensor),
  2. when conducting a pressure test through the choke manifold and
  3. when pressure testing a new casing string.

- A function test of the casing gauge should be conducted prior to penetration of the critical sour zone.

1.6.7.3 Compound Mud Gauges

IRP Compound mud gauges employing dual Bourdon tubes shall be an acceptable alternative to dual gauge installations.

Compound mud gauges present both low and high pressure ranges using independent indicators on a single gauge face. The low pressure gauge is protected by a built-in pressure limiting device.

Compound gauges may be used either on the drill pipe or casing pressure side.

1.6.7.4 Choke Panel Gauges

IRP Choke panel pressure gauges should be as follows:

- Choke panel gauges with ranges excessively higher than the choke manifold rating are not recommended.
- Remote drill pipe pressure gauges should be readable from the choke location.
- A remote operated choke is required on all critical sour wells. A remote casing pressure gauge would then be available at or near the driller's console to maximize the information while circulating out a kick.

- A remote drill pipe pressure gauge should be installed, or readily accessible, at the choke manifold for all BOP classes. At a minimum the line must be laid to the manifold. These provisions are considered adequate for most applications.
- Assuming there is a tie in for a low-pressure gauge, the need for a second high pressure gauge should be left to operator/contractor discretion.
- Installation of gauges and sensors should be in a vertical or near vertical position to reduce the chance of solids build-up.
- Isolation valves should be utilized so that operations need not be shut down in the event of a failure.

1.6.7.5 Pressure Sensors

1.6.7.5.1 Overview

In general, diaphragm sensors are favoured for lower pressure applications such as Class I to Class IV rigs. Piston sensors are generally favoured for higher pressure applications such as Class IV to Class VI rigs.

Diaphragm sensors exhibit excellent sensitivity and consistent performance but are relatively easy to damage. They must be inspected or replaced periodically to ensure segregation of the drilling fluid and gauge liquid (e.g., glycol, low temperature hydraulic fluid or instrumentation fluid). Diaphragm type sensors are not designed to withstand differential pressure and therefore may be subject to rupture if the gauge liquid chamber is not completely filled.

Piston style sensors are considerably more rugged and less prone to catastrophic failure. They do, however, exhibit somewhat jerky or “stair step” pressure build up, especially when piston or sleeve wear is significant. This irregular pressure build up is caused by a threshold differential pressure required to overcome friction and may be only a few kPa to perhaps a few hundred kPa.

The pressure on the gauge side of the sensor may be less than the true pressure by a value approximated by the threshold friction pressure of the sensor. Piston friction may be particularly evident when the drilling fluid is heavily solids laden.

Studies have also shown that piston sensors may yield higher than actual gauge readings when the casing or drill pipe pressure is declining.

This hysteresis error and lower sensitivity is significant at the lower end of the pressure range but is acceptable at higher pressures. Piston sensors are particularly suitable for long hose runs (exceeding 15 m) or for applications where multiple gauges are driven by one sensor.

1.6.7.5.2 Accuracy and Calibration

IRP Pressure measuring devices shall be as follows:

- Pressure measuring devices shall be accurate to at least ±2% of full scale.
- Pressure gauges shall be selected within 20% and 80% of full scale.
- Pressure measuring devices shall be periodically calibrated with a master pressure measuring device or dead weight tester to at least three equidistant points of full scale (excluding zero and full scale as required points of calibration).
- Calibration records shall be maintained and traceable by pressure measuring device unique serial number.
- Calibration intervals shall be a minimum of three months until recorded calibration history can be established and new intervals established. The maximum increment for intervals is three months.
- A sticker shall be applied to each pressure measuring device indicating next calibration date as determined by calibration history of said device.

1.6.7.5.3 Maintenance and Documentation

IRP Maintenance of pressure sensors should be conducted at least monthly and prior to penetration of the critical sour zone.

Routine maintenance of sensors would be conducted as per manufacturer specifications.

1.6.8 Initial Choke Manifold Certification and Documentation

IRP Choke manifold documentation and certification should be as follows.

- Manifold documentation should be retained by the equipment owner and updated following any changes or replacements.
- All welds should be 100% radiographed for initial certification and documented.
- Documentation should include component mill certificates with written confirmation indicating compliance with NACE criteria.
- Component mill certificates should be obtained for all new equipment for purposes of initial certification. The following information should be supplied for each component:
    - name of manufacturer
    - date of manufacture
    - serial number

- part numbers and lot numbers (to allow tracking to mill certification)
- material grade
- chemistry
- physical properties
- actual hardness
- heat treatment used

- One flange of each component should be die stamped with a unique identifier. It is recommended that the unique identifier be cross referenced via documentation to the inspection company, year and month of inspection and component number.
- All valves subject to inspection should be tagged.
- The assembled system should be pressure tested to rating using a low viscosity, solids-free liquid.
- Component suitability, manifold assembly, pressure testing and identification should be witnessed and approved by a certified inspection company.
- A detailed manifold and piping schematic illustrating individual component parts and unique identifier should be prepared.
- Maintenance and repair of equipment should be conducted in accordance with manufacturer's recommendations. All repairs, including weldments, should be certified by a qualified inspection company and fully documented.

1.6.9 Shop Servicing and Pressure Testing

1.6.9.1 Shop Servicing

Regular shop servicing of BOP choke manifolds is not required if the manifold has been properly maintained and regularly pressure tested.

IRP Choke manifolds should be shop serviced either every 5 years (as per API STD 53) or in alignment with the rig's 1000 day inspection (as per CAODC RP 1.0), whichever comes first.

IRP Any time the choke manifold is subjected to uncontrolled flow of reservoir fluids, the choke manifold should be shop serviced and tested prior to that choke manifold going back into service.

After a kick or well control operation, shop servicing may be carried out at contractor or operator discretion.

The shop servicing technician should consider the following:

- The choke(s) and valves used in the well control operation should be disassembled and the internals visually inspected. Any components showing signs of damage or serious wear should be replaced. The reassembled choke and valves should be pressure tested to meet or exceed original manufacturer specifications.

- Ultrasonic thickness testing of piping and related fittings should be considered with special attention given to areas of change in piping direction. Any remaining wall that will not meet the working pressure at the minimum yield strength should be replaced.
- All bolting shall be replaced.
- All ring gaskets shall be replaced.

IRP If a manifold has not been in service in the last 6 months, a visual inspection of the manifold must be conducted by a trained inspector and the manifold must pass a pressure test. The manifold must undergo complete shop servicing if either the inspection or pressure test fail.

1.6.9.2 Pressure Testing

IRP Choke manifolds shall be pressure tested prior to use.

IRP Choke manifold testing procedures should be as follows:

- The integrity of the BOP choke manifold and its related piping should be established by hydrostatically pressure testing to full work rating.
- A solids-free, environmentally friendly fluid should be used for pressure testing.
- The manifold and all piping upstream of the choke should be pressure tested to manifold working pressure rating.
- Each valve should be individually tested in both the open and closed position with the exception of the last valve in a series, which is only tested closed.
- During drilling, the choke manifold pressure testing frequency is outlined in 1.14.3.3 Choke Manifold Pressure Testing.

1.7 Mud-Gas Separators

1.7.1 Scope

This chapter addresses the minimum requirements for mud-gas separator use in sour wells. The technical specifications are designed to provide adequate capacity to handle kicks of considerable volume without exceeding the acceptable back pressure in the vessel while maintaining good separation efficiency.

Two types of mud-gas separators are discussed:

1. Open bottom, atmospheric pressure mud-gas separators (also referred to as “poor boy” separators).
2. Closed, pressurized mud-gas separators.

Technical specifications include the following:

- Inlet line and vent lines
- Recommended materials
- Fabrication
- Installation
- Maintenance
- Certification
- Documentation

The designs are best practices at the time of writing. Alternate designs are acceptable but should be thoroughly engineered and undergo a hazard and operability review.

1.7.2 Codes and Standards

The following codes and standards are referenced in this section:

- ASME B31.3-2012 Process Piping
- ASME BPVC-VIII-1-2010 - 2010 ASME Boiler and Pressure Vessel Code (BPVC), Section VIII, Division 1: Rules for Construction of Pressure Vessels, Includes 2011 Addenda Reprint. 2010.
- ASME BPVC-IX-2010 - 2010 ASME Boiler and Pressure Vessel Code (BPVC), Section IX: Welding and Brazing Qualifications, Includes 2011 Addenda Reprint. 2010.

- NACE MR0175/ISO 15156 Materials for use in H2S-containing environments in oil and gas production, 2009 Edition.

1.7.3 General Requirements

IRP The following general requirements for mud-gas separators shall apply to critical sour wells:

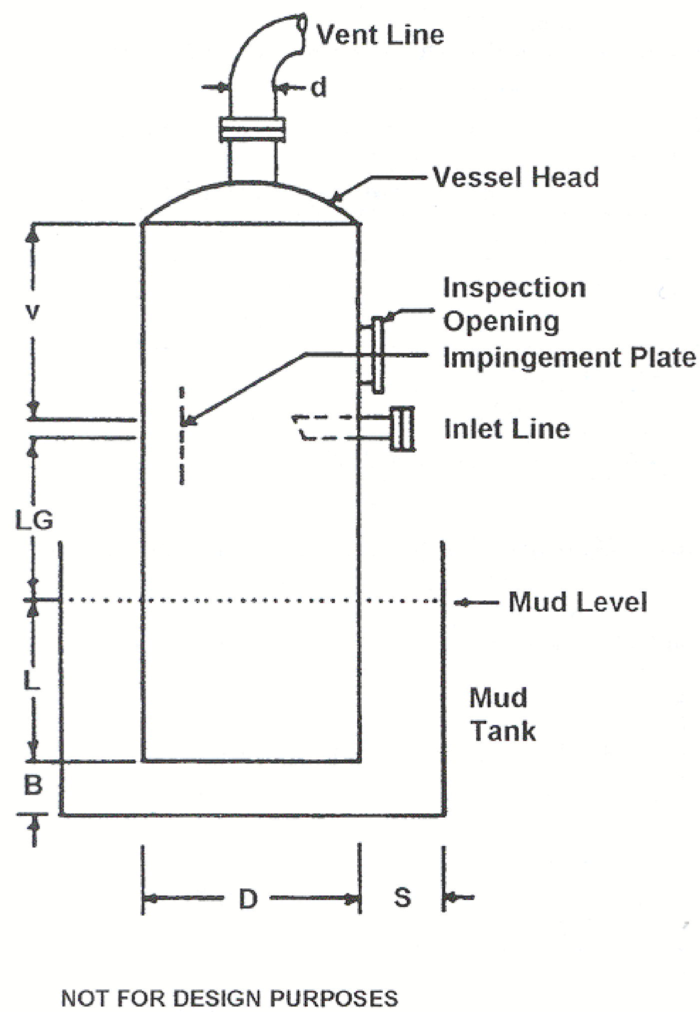
- Two mud-gas separation devices are required.
- One mud-gas separator is acceptable, upon approval from the appropriate regulatory agency, if the well is low complexity, low impact and/or a simple ERP well (see 1.1.3 Well Types).
- One device must be an atmospheric open bottom mud-gas separator and must conform to the specifications in Table 13. Open bottom mud-gas separators are recommended for critical sour drilling for their simplicity, lack of moving parts and high reliability.
- Mud system contamination potential is determined using production interval history of gas rates and liquid production potential. Consider using a pressurized separator if the zone of interest is known to produce hydrocarbon liquids or water.
- Each separator should be fed independently with separate inlet lines from each wing of the choke manifold. Choke and piping arrangement from the manifold shall allow independent flow control to each mud-gas separator.
- Each separator requires an independent vent line to the flare facility (i.e., flare stack, flare pit, incinerator).
- All materials used in vessels, inlet lines and vent lines for mud-gas separators must be suitable for sour service and have a maximum yield strength not exceeding 550 MPa. Suitable materials are detailed in Table 14.
- Mud-gas separator vent lines shall slope downward to the flare pit or tank.

1.7.4 Open Bottom Mud-Gas Separators

IRP Atmospheric pressure open bottom mud-gas separators should be as follows.

Figure 7 illustrates the recommended configuration for atmospheric pressure open bottom mud-gas separators. Flat topped vessels are not recommended.

Figure 7. Open Bottom Mud–Gas Separator Recommended Configuration



Refer to Table 13 for an explanation of the diagram components.

1.7.4.1 Vessel Placement

Vessel placement should be as follows:

- Position the vessel in the first mud tank compartment downstream of the sand trap or shale shaker.
- Install the vessel away from tank corners and at least 0.5 m away from tank walls. This horizontal positioning is more important when using shallower submersion depths such as 1 m.
- Position the base be at least 0.3 m above the tank floor.

- Ensure the vessel should be removable.
- Ensure the compartment housing the vessel shall be equipped with a dump gate.

Alternatively, the open bottom mud-gas separator(s) may be placed in a remote tank (as described in 1.7.7 Remote Open Bottom Mud-Gas Separators).

1.7.4.2 Dimensional Specifications

Table 13. Dimensional Specifications for Atmospheric Pressure Open Bottom Mud-Gas Separators

Separator Configuration			
Identifier (Figure 7)	**Description**	**Specification**	
D	Separator Inside Diameter	See below	
d	Vent Line Inside Diameter	See below	
L	Liquid Level	Minimum height 1 m	
v	Vapour Space	Distance from top of the inlet line (inside the separator) to the tangent line of the vessel head Minimum height 0.9 m	
LG	Liquid-Gas Disengagement Space	Distance from bottom of the inlet line (inside the separator) to the maximum Liquid Level Minimum height 0.3 m	
Separator Placement in Mud Tank			
B	Open Bottom Underflow	Minimum height 0.3 m	
S	Distance to Tank Wall	Minimum 0.5 m	
Separator Internals			
Impingement Plate	• If used, should be removable and made from an abrasion resistant material. • Do not weld the plate directly to the separator body.		
Baffles	Should be installed to augment separator efficiency.		
Inside Diameter (D) and Vent Line (d) Specifications			
Drilling Depth Less Than (m)	**(D) Minimum Vessel Inside Diameter (mm)**	**(d) Minimum Vent Line Inside Diameter (mm)**	
		With 1 m of Liquid Level (L)	**With 2 m of Liquid Level (L)**
750	355.6	101.7	101.7
1,800	609.6	152.4	127.0
2,700	660.4	172.9	152.4
3,600	762.4	203.2	152.4
5,000+	914.4	254.0	203.3

Vessel diameter was determined using a vapour load factor (k) of 0.11 m/s.

1.7.4.3 Material Specifications

Materials used for the vessel body and head should have a maximum yield strength of no greater than 550 MPa. Recommended materials and fittings are outlined in Table 14.

Table 14. Material and Fitting Specifications Atmospheric Pressure Open Bottom Mud-Gas Separators

Regular Materials	Standard	Grades
Plate	ASTM A516	Grade 65
	ASTM A516	Grade 70
Body and Piping	ASTM A106	Grade B
	ASTM A53	Grade B
	API 5L	Grade B
	API 5L	Grade X42
	CSA Z245.1	Grade 241 Category 1
	API 5CT	H40, J55, K55 seamless casing (if hardness tested)
Low-Temperature Materials		
Plate	ASTM A516	Grade 65 including Supplementary 5
	ASTM A516	Grade 70 including Supplementary 5
Inlet Piping	ASTM A333	Grade 6
	CSA Z245.1	Grade 241 Category II

1.7.4.4 Welding Specifications

Spiral welded pipe should not be used for mud-gas separator bodies.

Weldments on external fittings such as vessel inlet and outlet flanges should be reinforced and stress relieved.

1.7.4.5 Wall Thickness

Walls should be thick enough to allow for erosion and corrosion. Consider additional wall thickness in the inlet area when tangential inlet nozzles are used.

1.7.4.6 Internal Components

Design and position the internal components to augment separation efficiency. The internal profile of the vessel head should smoothly direct separated gas into the vent line.

To facilitate removal and repairs, internal components subject to wear should not be welded in place. When internal components are welded in place the wall behind the components may be difficult to inspect for signs of corrosion.

1.7.4.7 Inspection Opening

Design the inspection opening (access hatch) size and position to facilitate inspection and refurbishment of internal components. Vessel plate materials are suitable for fabrication of the inspection hatch.

Alternatively, the inlet line flange can double as an inspection opening.

1.7.4.8 Tank Fluid Level

Maintain tank fluid level (head) equal to or greater than the fluid height requirements as indicated in Table 13. Check the compartment housing the separator frequently to avoid solids build up around the bottom of the vessel.

1.7.5 Inlet Lines for Mud-Gas Separators

IRP Inlet lines to atmospheric or pressurized mud-gas separators should be configured as follows:

- Inlet lines may be exposed to physical and thermal shock. Low temperature tough rated materials are recommended. Table 14 outlines recommended materials and fittings and illustrates grades rated low temperature tough.
- Seamless pipe is recommended for use as inlet lines.
- Line diameter should have a 25.4 mm (1 in.) larger nominal outside diameter (OD) than the BOP choke line OD to limit maximum flow velocity to the mud-gas separator.
- Inlet lines should be accessible full length. No portion of the line should be submerged in drilling fluid or positioned between bulkheads. If the line is submerged it must be inspected for wall thickness (UT) and integrity prior to spud of the critical sour well.
- Keep the line as straight as possible with internal diameters and wall thickness consistent throughout the assembly.
- Securely stake or weight the section of the inlet line from the manifold to the mud tank. It is important to secure in place the section running vertically adjacent to the mud tank wall because there is potential for vibration.
- Bull-plugged or targeted tees should be used for changes in piping direction.
- Connections should use flanges or hammer unions. Elastomer component materials must be compatible with the drilling fluids to be used on the well.
- Welds should comply with 1.9 Welding.
- During winter operations the line from the BOP stack to the mud-gas separator should be filled with water-soluble antifreeze compatible with the BOP stack and

mud-gas separator components. Diesel is not recommended for use as antifreeze because diesel/mud segregation may allow water-based fluid accumulation and line blockage.

Most of the requirements and specifications for inlet lines are identical for atmospheric (open bottom) and pressurized (enclosed) mud-gas separators. The exceptions are as follows:

- No valves or other mechanical restrictions are permitted in the intake line for atmospheric pressure mud-gas separators. Inline antifreeze recovery drainage ports are acceptable providing they do not compromise system integrity or function.
- Valves or mechanical restrictions are permitted for pressurized systems.
- For pressurized systems, inlet line material selection depends on design conditions relating to required pressures and temperature expectations. ASME B31.3 may be used as a guideline to thickness requirements.

1.7.6 Vent Lines for Open Bottom Mud-Gas Separators

IRP Vent lines for open bottom mud-gas separators should be configured as follows:

- Vent line materials and fittings should follow the recommendations shown in Table 14.
- Vent line sizing should follow the schedule in Table 13 while considering fluid head level maintenance. If desired and available, vent line sizes halfway between those shown for 1 m and 2 m of fluid head may be utilized in conjunction with 1.5 m of minimum fluid head.
- Vent lines should slope downward to the flare pit and be securely staked or weighted. It is important to secure in place the section running vertically adjacent to the mud tank wall because there is potential for vibration.
- Wear and vibrational loading (fatigue) should be considered when vent lines are constructed from thin walled pipe.
- Radius bend fittings are acceptable for changes in pipe direction but wall thickness and internal diameters of lines and fittings should be consistent throughout the entire vent line.
- Each open bottom mud-gas separator shall have a separate vent line extending to the flare pit.
- Each specific installation should consider the possibility of flashback and the potential ramifications of flashback. These concerns are most prevalent when the largest vent line diameters are required and when low flow rates occur.

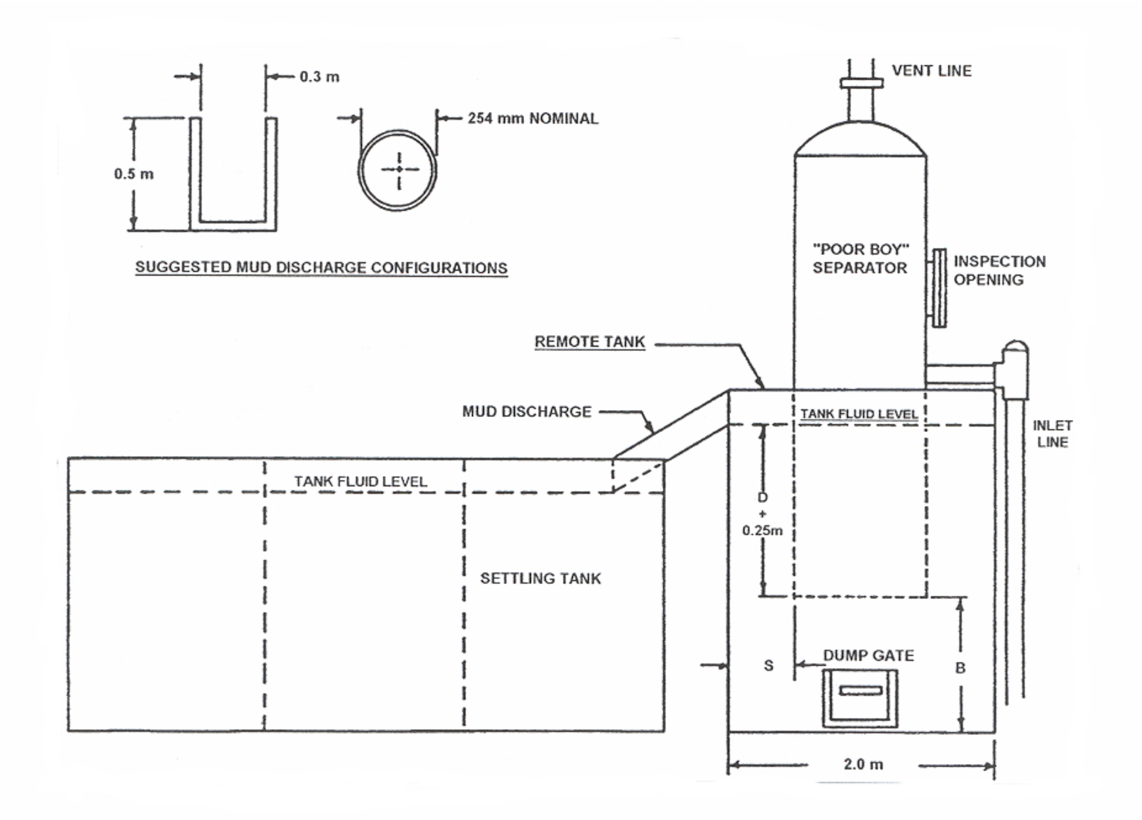
1.7.7 Remote Open Bottom Mud-Gas Separators

IRP Remote open bottom mud-gas separators should be installed in a tank equipped with a dump gate and should be positioned near the rig mud tanks.

IRP The gravity mud return line must be sized to adequately handle the highest anticipated mud return rate.

Figure 8 illustrates the suggested layout and sizing.

Figure 8. Open Bottom Mud-Gas Separator Remote Layout and Sizing



1.7.8 Enclosed Mud-Gas Separators

An enclosed mud-gas separator may be used in conjunction with an open bottom mud-gas separator on critical wells.

Additional information regarding pressure vessels is available in [IRP Volume #4 - Well Testing and Fluid Handling.]

1.7.8.1 Design Specifications

IRP Enclosed mud-gas separator design should be as follows:

- Wall thickness should be determined based on the maximum internal operating pressure required.
- The design pressure should be at least 1.1 times the maximum allowable working pressure (MAWP) or 200 kPa, whichever is greater.
- Standard pressure vessel stress calculations should be based on ASME BPVC-VIII-1-2010. A safety factor of 4.0 should be used for the maximum allowable stress value.
- Joint efficiency values depend upon weld procedure. X-ray requirements must be considered as follows:
  - 100% - 1.0
  - 90% - partial
  - 80% - no X-ray
- Corrosion allowance of a minimum of three mm should be added to design wall thickness.
- Wall thickness should be a minimum of six mm.
- Atmospheric separator vessels should be sized for gas flow rates at 100 kPa absolute pressure (0 kPa gauge pressure) at 15 ^{0}C.
- Pressurized separator vessels using constant internal vessel pressure should be sized for gas flow rates at 80% of MAWP at 15 ^{0}C.
- Pressurized separator vessels using variable internal pressure should be sized for gas flow rates at 80 % of MAWP at 15 ^{0}C.
- The vapour space section between the inlet line and the vessel head tangent line should have a minimum height of 0.9 m.
- The gas liquid disengagement section between the inlet line and the maximum internal fluid level should be a minimum of 0.3 m.
- The liquid section should consist of an active fluid zone between maximum and minimum fluid level, a buffer zone between minimum level and mud outlet and a sump zone below the mud outlet. Each of these three zones should have a minimum height of 0.3 m.
- The mud outlet line should be capable of handling 1.5 m^3/min of drilling fluid. A vortex breaker may be desirable in certain cases.

1.7.8.2 Required Components

IRP Enclosed mud-gas separators must include the following components:

- A fluid level control device (with a manual override for internal fluid level control and independent fluid level indicator).
- A mud outlet control valve with an opening equal to mud outlet line diameter.
- A mechanical control for atmospheric enclosed vessels or a pneumatic or electric control for pressurized vessels.
- A minimum 76 mm diameter full opening clean out valve for solids removal. The valve should include a position indicator and lock.
- A properly functioning pressure gauge mounted on the vessel vapour space.
- A 101.7 mm diameter or larger relief line (such as 152.4 mm) must be run to the pit and securely staked or weighted.
- A quick opening inspection hatch should be installed according to UG 46 ASME BPVC-VIII-1-2010.

The design should consider the following:

- A reliable, easy to read, externally mounted internal fluid level indicator is strongly recommended.
- The separator support structure should safely support a vessel completely full to the overflow fluid level (drilling fluid with a density of 2100 kg/m^3).

1.7.8.3 Fabrication and Operating Guidelines

IRP Enclosed mud-gas separator vessels should adhere to the following fabrication and operating guidelines:

- Vessels used in unheated areas should be fabricated from low temperature tough rated materials. Atmospheric enclosed vessels should be fabricated from materials listed in Table 13.
- Pressurized vessel materials shall meet ASME BPVC-VIII-1-2010.and NACE MR0175/ISO 15156.
- Welding on pressurized separators shall meet the boiler or pressure vessel code appropriate to the regulatory region (e.g., The Alberta Boiler and Pressure Vessel Code) and shall be performed as per ASME BPVC-IX-2010.
- Pressure vessel identification plates are required by the local governing boiler inspector. Atmospheric tanks should contain a similar nameplate. Flow capability is not generally included on the nameplate of pressure vessels.
- Enclosed separators should be accompanied by an operation and maintenance manual describing primary and manual operation, inspection, function testing and routine maintenance. An installation diagram should be included along with a system schematic.

- The drilling fluid outlet from atmospheric vessels should be directed to the sand trap or shaker box. Procedures for sour fluid returns must be developed based on the configuration for the rig selected to drill the well.
- The drilling fluid outlet from pressurized mud-gas separators should be directed to a secondary degasser (such as a vacuum degasser) to remove residual entrained gas.
- Secondary degassers should be sized to handle the anticipated mud return rate.
- Separated gas must be directed away from the mud tank and work areas.
- Fluid level control mechanisms should be function tested upon installation, when testing the choke manifold and prior to penetration of any critical sour zones.
- Mud-gas separator systems should be fully inspected after any well control operation and operator/contractor discretion. Any repair or replacement should conform to the original requirements and be documented by the equipment owner.

1.7.9 Vent Lines for Enclosed Mud-Gas Separators

IRP The vent lines for enclosed mud-gas separators should be configured as followed:

- Materials and fittings used in vent lines should follow the recommendations in shown in Table 14.
- Each enclosed separator must have a separate vent line extending to the flare pit.
- Each specific installation should consider the possibility of flashback and the potential ramifications of flashback, particularly at low flow rates.
- Vent lines for atmospheric and pressurized enclosed separators should be sized to provide a maximum back pressure equivalent to 70 % of vessel MAWP assuming isothermal flow at 15 ^{0}C. Vent lines must be a minimum of 101 mm in diameter.
- Pressurized separators operating under constant internal pressure utilize a control valve located in the vent line. This variety is not recommended.

1.8 Drill String Design and Metallurgy

1.8.1 Scope

The drill string design and metallurgy recommended practices have been developed recognizing the need for drill pipe integrity during both routine drilling and well control operations.

This chapter includes the design and metallurgic requirements for tool joints (using API or non-API thread forms) and drill pipe grades SS75, SS95 and SS105.

> **Note:** As of the 2014 edition of IRP 1, API Grades E75, X95, G105 and hardness tested API grades E, X and G (referred to as HE, HX and HG) are no longer permitted in critical sour operations. All references to these grades have been moved to Appendix A - 2014 Revisions for historical reference. The entire section for hardness testing (1.8.6 Hardness Tested API Grade Drill Pipe Specification) has been moved to Appendix A - 2014 Revisions.

The drill string includes the following components below the Kelly Saver Sub to the bottomhole assembly (BHA):

- Pup Joints
- Heavy Weight Drill Pipe
- Stabbing Valves
- Kelly Cock
- Downhole Floats (inside BOP)

Drill collars and BHA are not included in the scope because:

1. These components are at the bottom of the drill string and their failure during drilling would have little negative impact on well control capability.
2. These components are not highly stressed during tripping and would not likely fail.

1.8.2 Codes and Standards

The following codes and standards are referenced in this section:

- API Spec 5CT Specification for Casing and Tubing, Ninth Edition. 2011.
- API Spec 5DP Specification for Drill Pipe, Frist Edition. August 2009. (Identical adoption of ISO 11961:2008).

- API RP 7G Recommended Practice for Drill Stem Design and Operation Limits, Includes Addendum 1 and 2 (2009), 16th Edition. 1998.
- ASTM E18 - 12 Standard Test Methods for Rockwell Hardness of Metallic Materials, 2012 Edition. 2012.
- ASTM E23 - 12c Standard Test Methods for Notched Bar Impact Testing of Metallic Materials. 2012.
- ASTM E112 - 12 Standard Test Methods for Determining Average Grain Size. 2012.
- NACE TM-0177-2005 Laboratory Testing of Metals for Resistance to Sulfide Stress Cracking and Stress Corrosion Cracking in H_2S Environments. 2005.
- NACE MR0175/ISO 15156 Materials for use in H_2S-containing environments in oil and gas production, 2009 Edition.

1.8.3 Drill Pipe Grades

IRP All drill pipe must be suitable for sour service. Grade SS75, SS95 or SS105 shall be used.

Non-SS rated drill pipe shall not be used for Critical Sour Wells. The only potential exception is higher grade drill pipe that may be used when SS105 is insufficient for the tensile or torque loading. Use of non-SS drill pipe requires regulatory approval and environmental control is mandatory because non SS drill pipe is highly susceptible to both H_2S and chloride-induced failure.

Using heavier wall Grade SS95 or SS105 pipe is preferred over higher grade drill pipe when the tensile or torsional capability of regular weight Grade SS95, SS105 or heavy wall Grade SS 75 is insufficient.

1.8.4 Drill String Overpull Design Considerations

IRP The final margin of overpull at any point in the drill string shall be in the order of 30,000 - 50,000 daN over string weight.

Tensile and torsional loads should be modelled and determined using an engineering assessment.

1.8.5 Drill Pipe Class Tensile Rating

IRP Only premium class or better drill pipe should be used for critical sour drilling. Premium Tensile Ratings are as per API RP 7G.

Tensile ratings for drill pipe design can be increased to New Drill Pipe rating if pipe wear inspection shows less than 10% wall loss (as per API RP 7G).

1.8.6 Exposure Control

IRP Exposure control should be used for all grades of drill pipe.

IRP Strict exposure control shall be used when S135 pipe is used.

Exposure control can be accomplished in several ways:

1. Maintain sufficiently high drilling fluid density to ensure only drilled gas is permitted to enter the annulus.
2. Maintain drilling fluid pH (in a water-based system) above 10.0 to solubilize the sulphides.
3. Employ scavengers to treat out H_2S.
4. Treat the system with inhibitors to coat the tubulars and provide some protection against short term exposure to H_2S.

1.8.7 SS Grade Drill Pipe Tube Specifications

1.8.7.1 Certification and Documentation

IRP SS grade drill pipe tube must meet the criteria outlined in this section.

Mill certification shall be present for all material criteria stipulated herein, including hardness test results.

Drill string service history should include inspection results and any string refurbishment.

Suitability for continued sour service should be based on the above criteria and at operator/contractor discretion.

1.8.7.2 Tensile Properties

IRP Tensile properties for SS grade drill pipe tube shall be as follows:

- Drill pipe tube shall meet the limits listed in Table 15.
- Specified elongation shall be a minimum of 17%.
- Testing frequency should be one specimen per heat per heat treat lot or every 200 tubes, whichever is more frequent.

Table 15. SS Drill Pipe Tensile Properties

	SS75		SS95		SS105	
Yield Strength	517 MPa 75 Ksi	655 MPa 95 Ksi	655 Mpa 95 Ksi	758 MPa 110 Ksi	724 MPa 105 Ksi	827 MPa 120 Ksi
Ultimate Tensile Strength	655 MPa 95 Ksi	793 MPa 115 Ksi	724 MPa 105 Ksi	896 MPa 130 Ksi	793 MPa 115 Ksi	965 MPa 140 Ksi

1.8.7.3 Hardness Specifications

IRP Hardness specifications for SS grade drill pipe tube shall adhere to the following criteria:

- Drill pipe tube shall meet the limits listed in Table 16.
- Hardness level is verified on a ring sample with nine impressions in each of four quadrants.
- Hardness Testing conforms to API 5CT Through Wall Hardness Test figure and ASTM E18.
- Test frequency should be one set per heat per heat treat lot or every 200 tubes, whichever is more frequent.
- A minimum of one impression (Rockwell or Brinell) on each tube is required.

Table 16. SS Drill Pipe Hardness Rockwell “C” (HRC)

		Single Point Reading	
Grade	**Maximum Average**	**Maximum**	**Minimum**
SS75	22.0 HRC	24.0 HRC	
SS95	25.0 HRC	27.0 HRC	18.0 HRC
SS105	28.0 HRC	29.0 HRC	21.0 HRC

1.8.7.4 Toughness Specifications

IRP Toughness specifications for SS grade drill pipe tube shall be as follows:

- Toughness specification for SS Grade tube shall require the minimum longitudinal Charpy "V" notch impact, from a 3⁄4 size specimen at room temperature as listed in Table 17 (as per ASTM E23). Room temperature is defined in API 5DP as 21 °C ± 3° (70 °F ±5°).
- Testing frequency should be one set of three specimens per heat per heat treat lot or every 200 tubes, whichever is more frequent.

Table 17. SS Drill Pipe Toughness Minimum Single Value CHARPY “V”

	Minimum	
Grade	**Joules**	**ft-lbf**
SS75	70	50
SS95	80	59
SS105	80	59

1.8.7.5 H_2S Resistance Specifications

IRP H_2S resistance specifications for SS grade drill pipe tube shall be as follows:

- SS drill pipe shall have a demonstrated minimum threshold of 85% of the SMYS for 720 hours per NACE TM-0177 Test Method A using Test Solution A.
- Testing frequency should be one specimen per heat per heat treat lot or every 200 tubes, whichever is the more frequent.
- If any heat has a failed specimen, two additional specimens from the same heat and heat treat lot are required as a retest. The heat is unacceptable if either specimen fails.

1.8.7.6 Chemistry Specifications

IRP Chemistry specifications for SS grade drill pipe tube shall be as follows:

- Recommended chemistry specifications for SS grade drill pipe tube should include the maximum and minimum weight percent limits as listed in Table 18.
- For sulphur levels approaching the specified maximum, a manganese limit of 1.2 % maximum is recommended to avoid reduced SSC resistance and material toughness.
- Additional micro alloys or processing materials may be utilized at manufacturer discretion.
- Alternative chemistries may be acceptable but must undergo an engineering assessment.

Table 18. Recommended SS Drill Pipe Chemistry Weight Percent

	SS75		SS95		SS105	
	Min	Max	Min	Max	Min	Max
Carbon	-	0.38	0.25	0.35	0.25	0.35
Manganese	-	1.60	0.40	1.00	0.40	1.00
Chromium	-	-	0.90	1.30	0.90	1.30
Molybdenum	-	-	0.30	0.60	0.30	0.60
Sulphur	-	0.010	-	0.010	-	0.010
Phosphorous	-	0.015	-	0.015	-	0.015

1.8.7.7 Transformation and Grain Size

IRP Minimum transformation to martensite after quenching should be 90% across the full wall of the SS95 and SS105 drill pipe wall.

IRP Grain size specification shall be six or finer as per ASTM E112-12.

1.8.7.8 Tube and Tool Joint Transition

IRP The transition from the drill pipe ID to the standard upset ID should occur over a sufficient length as to minimize drill pipe tube fatigue failures adjacent to the upset area.

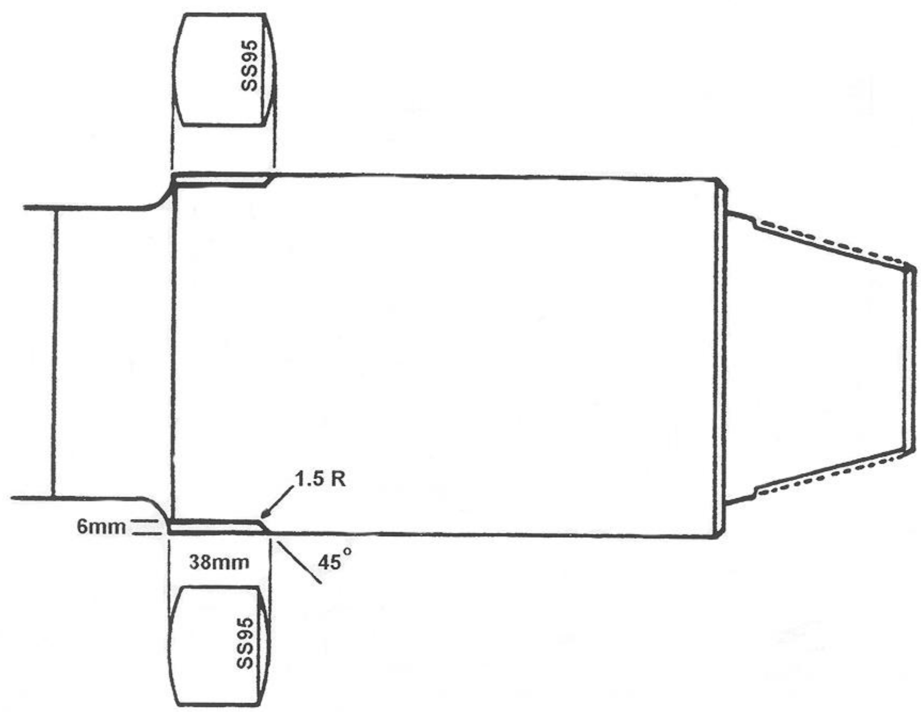
This minimum transition should be approximately 76.2 mm (3") for standard wall thickness drill pipe and commensurately longer for higher strength and weight pipe so the taper angle remains relatively unchanged.

1.8.7.9 Drill Pipe Identification

IRP All drill pipe conforming to SS specifications must be marked with a unique identifier visible from the driller's location.

A suggested method is shown in Figure .9.

Figure 9. Figure: Suggested Drill Pipe Identification



1.8.8 SS Grade Tool Joint Specification

Only one grade of SS Tool Joint is used in critical sour drilling. Tool joints may use API or non-API thread forms.

1.8.8.1 Certification and Documentation

IRP Tool joints, using API or non-API thread forms, used on all grades of SS tube must meet the specifications outlined in this section.

Mill certification shall be present for all material criteria stipulated herein, including hardness test results.

Drill string service history should include inspection results and any string refurbishment.

Suitability for continued sour service should be based on the above criteria and at operator/contractor discretion.

1.8.8.2 Tensile Property Specifications

IRP Tensile properties for SS grade tool joints shall be as follows:

- Tool joints shall meet the limits listed in Table 19.
- Specified elongation shall be a minimum of 15%.
- Specified reduction in area shall be a minimum of 35%.
- Testing frequency should be one specimen per heat per heat treat lot or every 200 tool joint box/pin set, whichever is more frequent.

Table 19. SS Tool Joint Tensile Properties

	Minimum	Maximum
Yield Strength	758 MPa/110 Ksi	862 MPa/125 Ksi
Ultimate Tensile Strength	862 MPa/125 Ksi	1000 MPa/145 Ksi

1.8.8.3 Dimension and Torsion Specification

IRP Dimension and Torsion specifications for SS tool joints shall be as follows:

- Tool joint design must be evaluated for torsional suitability.
- For API thread forms, in conjunction with reduced yield strength, the tool joint pin ID and/or box OD shall be chosen to maintain tensile and, in particular, torsional strength.
- Operators shall be aware of and utilize drill string performance properties in the drill string design.

1.8.8.4 Hardness Specifications

IRP Hardness specifications for SS tool joints shall be as follows:

- Hardness specification for SS tool joints shall be limited to a maximum average of 30.0 HRC with no single reading above 32.0 HRC.

- Testing frequency should be one test traverse per heat per heat treat lot or every 200 tool joint box/pin set, whichever is the more frequent.
- A test traverse sample shall consist of:

  1. a full length hardness traverses mid wall and
  2. a longitudinal strip type cross section near the inner and outer surfaces.

- One impression should be taken on every tool joint element (pin and box) prior to threading and hard banding.
- Hardness testing is as per ASTM E18 - 12.

1.8.8.5 Toughness Specifications

IRP Toughness specifications for SS grade tool joints shall be as follows:

- Minimum average longitudinal Charpy "V" notch impact value shall be 90 J (66 ft-lbf) for a standard specimen at room temperature as per ASTM E23 98.
- Testing frequency should be one set per heat per heat treat lot or every 200 tool joint box/pin set, whichever is the more frequent

1.8.8.6 H_2S Resistance Specifications

IRP H_2S resistance specifications for SS grade tool joints shall be as follows:

- SS tool joints shall have a demonstrated minimum threshold of 493 MPa/72Ksi (65 % of the SMYS) for 720 hours per NACE TM-0177 Test Method A using Test Solution A.
- Testing frequency should be one traverse per heat per heat treat lot or every 200 tool joint box/pin set, whichever is the more frequent.
- If any heat has a failed specimen, two additional specimens from the same heat and heat treat lot are required as a retest. The heat is unacceptable if either specimen fails.

1.8.8.7 Chemistry Specifications

IRP Chemistry specifications for SS grade tool joints shall be as follows:

- Recommended chemistry specifications for SS grade tool joints should include the maximum and minimum weight percent limits as listed in Table 20.
- Alternative chemistries may be acceptable but must be reviewed and approved by a qualified technical expert.

Table 20. Recommended SS Tool Joint Chemistry Weight Percent

	Weight Percent	
	Min	**Max**
Carbon	0.25	0.35
Manganese	-	1.00
Chromium	0.70	1.30
Molybdenum	0.40	0.70
Sulphur	-	0.010
Phosphorous	-	0.015

1.8.8.8 Transformation and Grain Size

IRP Minimum transformation to martensite after quenching should be 90% across the full wall.

IRP Grain size specification shall be six or finer as per ASTM E112-12.

1.8.8.9 Hard Banding

IRP Hard banding for SS grade tool joints shall be as follows:

- Hard banding should be applied to tool joints as per the manufacturer application manual.
- The hard band groove should be of limited pre-cut depth avoiding sharp shoulders and should be applied with preheat after final temper, avoiding excessive innermost thread temperature.
- Welding should be performed in an inert atmosphere with matrix hardness limited and using an appropriate filler material.
- Recommended hard banding types include "casing friendly" smooth or flat ground surface varieties.

1.8.9 Inspection

IRP Inspections must follow API RP 7G-2.

IRP Drill pipe should meet or exceed specifications for Premium Class Drill Pipe as defined in API RP 7G, Section 10. Applicable sections are all subsections of 10.1 through 10.11.

1.8.9.1 Frequency

An inspection is required prior to the penetration of the critical sour zone unless

1. an inspection has been conducted on each pipe within the last 90 operating days or
2. the operator can otherwise demonstrate pipe adequacy.

Inspection timing is at operator/contractor discretion.

1.8.9.2 Documentation and Reports

The pipe owner is responsible for inspection documentation and updates. The documentation must be available to the operator or governmental agencies upon request.

Inspection reports should include the following:

- Rig Location
- Rig number
- Pipe owner
- Inspection company, date(s) and inspector
- Pipe Diameter, weight, grade and connection type
- Total number of joints inspected
- Inspection summary
- Classification of pipe (as per API RP7G)

1.8.10 Downhole Floats

IRP In general, downhole floats are recommended for use in the drill string while drilling the critical sour zone. The following should be considered:

- Suitability of downhole float use should be evaluated on a site-specific basis at the discretion of the operator and/or contractor.
- When blind shear rams are not installed, a drill string float or internal BOP should be used unless an engineering assessment indicates they are not required.
- Flapper type floats (if used) should be ported to facilitate procurement of shut-in drill pipe pressure. The recommended opening size in the float is approximately 6 mm.
- Downhole float should be made of H_2S resistant material meeting NACE MR 0175/ISO 15156.
- The advantages and disadvantages of downhole floats should be considered for each critical sour well.

1.8.10.1 Advantages of Downhole Floats

Some advantages of downhole floats are as follows:

- The downhole float maintains positive resistance to flow up the drill pipe during all phases of drilling and well control operations.

- The likelihood of plugging bit nozzles is reduced.
- Floats are advantageous when water drilling or when extreme overpressures are present.

1.8.10.2 Disadvantages of Downhole Floats

Some disadvantages of downhole floats are as follows:

- There is potential for drill pipe collapse.
- Drilling fluid is aerated.
- Surge pressures are increased which may induce lost circulation.
- The chance of hydraulic pipe sticking may increase and there may be difficulty in obtaining shut in drill pipe pressures during well control operations.

Note: The disadvantages of downhole floats can be significantly reduced with modifications to trip speed and pipe fill practices.

1.8.11 Upper Kelly Cocks, Lower Kelly Cocks and Stabbing Valves

IRP Upper and lower Kelly cocks should be utilized in all critical wells.

Note: For Top Drive rigs, the lower Kelly cock is a drill string valve between the top drive quill and the first joint of drill pipe.

IRP Kelly cocks and stabbing values should be as follows:

- Kelly cocks and stabbing valves should be certified by the manufacturer to withstand routine opening with 7000 kPa below the valve.
- Kelly cocks should be tested only from below.
- Kelly cocks and stabbing valves should not be opened during field pressure tests.
- Function tests and pressure tests of Kelly cocks and Stabbing valves should be performed during BOP stack pressuring testing (see 1.14.3.1 BOP Pressure Testing).

IRP Valve bodies should be as follows:

- Tensile strength should be equivalent to that of the tool joints in use.
- Kelly cocks and stabbing valves shall be manufactured to conform to the metallurgical requirements of the tool joints (see 1.8.8 SS Grade Tool Joint Specification) or with the requirements of NACE MR 0175/ISO 15156.
- Valve bodies should be inspected as per the drill pipe (see 1.8.9 Inspection).

- Internal working parts of Kelly cocks, stabbing valves and inside BOP's should be made of H_2S resistant material meeting NACE MR 0175/ISO 15156.

Note: Current regulations regarding the use of stabbing valves inside BOPs and associated subs are believed to be adequate. Proper equipment maintenance and placement on the rig floor is essential to properly prepare for any internal flow situation.

1.8.12 Heavy Weight Drill Pipe

IRP HWDP inspections should be as per SS drill pipe tube and tool joint inspections (see 1.8.9 Inspection).

IRP HWDP should have an inspection completed within 90 days of entering the critical sour zone.

An engineering assessment should be performed prior to commencing drilling operations to determine whether there is potential for SSC to occur within the HWDP section of a drill string during a stuck pipe scenario. Additional information about the specifics of HWDP for sour service is included in Appendix B Heavy Weight Drill Pipe.

1.9 Welding

1.9.1 Scope

The recommended welding practices and guidelines have been developed recognizing the need for equipment integrity during both routine drilling and well control operations. The welding procedures are designed to mitigate the effects of exposure to H_2S.

This chapter discusses the following parts:

- Casing Bowls
- Piping in manifolds
- Any other equipment subjected to pressure

1.9.2 Codes and Standards

The following codes and standards are referenced in this section:

- API 6A Specification for Wellhead and Christmas Tree Equipment, Twentieth Edition (ISO 10423:2009 Modification) Includes Errata (Jan. and Nov. 2011), Addenda 1(Nov 2011), 2 (Nov 2012), 3 (March 2013). 2010.
- ASME BPVC-VIII-1-2010 ASME Boiler and Pressure Vessel Code (BPVC), Section VIII, Division 1: Rules for Construction of Pressure Vessels, Includes 2011 Addenda Reprint. 2010.
- ASME BPVC-IX-2010 ASME Boiler and Pressure Vessel Code (BPVC), Section IX: Welding and Brazing Qualifications, Includes 2011 Addenda Reprint. 2010.
- ASTM E10 - 12 Standard Test Method for Brinell Hardness of Metallic Materials, 2012 Edition. 2012.
- ASTM E18 - 12 Standard Test Methods for Rockwell Hardness of Metallic Materials, 2012 Edition. 2012.
- MSS SP55 – 2011 ANSI Quality Standards for Steel Casings for Valves, Flanges, Fittings, and Other Piping Components – Visual Method for Evaluation of Surface Irregularities. 01-Oct-2011.
- NACE MR0175/ISO 15156 Materials for use in H_2S-containing environments in oil and gas production, 2009 Edition.

1.9.3 General Welding Recommended Practices

IRP Pressure containing parts fabricated by welding shall use the guidelines stated in this chapter.

IRP Qualified personnel, as mandated by provincial regulations, must perform the welding.

1.9.4 Welding Process

Select the welding process that best suits the field conditions and work area environment. Shielded Metal Arc is the preferred process for welding casing bowls to casing. For other welding (e.g., pipe in manifolds or pressure containment fabrication), any process may be used provided the work area is well protected from the elements and the work pieces easily manipulated.

1.9.5 Welding Electrodes

IRP Electrodes shall be selected to match the mechanical properties of mating pieces.

IRP Electrodes must have less than one percent nickel content when welding carbon steel and low alloy steel parts in sour service.

The weld procedure and subsequent tests will confirm the appropriateness of the selection.

1.9.6 Weld Procedure Specification

IRP A weld procedure specification (WPS) must be developed and welding performed in accordance with ASME BPVC-IX-2013. A sample WPS form is included in ASME BPVC-IX. The WPS shall include, at minimum, the essential and non-essential variables in the welding process as noted below:

- Materials to be welded
- Filler material, root and cap
- Pre-heat
- Interpass temperature
- Post heat
- Shielding gas
- Welding speed
- Direction of welding
- Welding technique
- Mechanical tests to be conducted (yield, tensile, elongation, reduction in area)
- Charpy Impacts as required
- Hardness traverse test to be specified

- Inspection requirements
- Records

IRP The WPS must include requirements from API 6A and NACE MR0175/ISO 15156 Parts 1 and 2.

1.9.7 Procedure Qualification Record

IRP ASME BPVC-IX-2012 requires completion of a Procedure Qualification Record (PQR). PQR representative parts shall be welded.

IRP Each change in essential variable must have a separate PQR.

Examples of essential variables include the following:

- Casing grade or material
- Weld process
- Filler material
- Shielding gas

IRP The PQR must include a Charpy Impact Test if any of the parts to be welded required a Charpy Test in order to be certified.

1.9.7.1 Casing Bowls

A valid substitution for casing bowls is wrought bars of equivalent dimensions, chemical composition, heat treatment and mechanical properties. Typical material specifications for manufacture of casing bowls are outlined below:

- AISI 4130 and AISI4140
- Quench and Tempered
- 414 MPa (60 ksi) minimum yield strength
- 586 MPa (85 ksi) minimum tensile strength
- Charpy impacts at -46°C (-50°F)
- 22 HRC maximum hardness

Actual casing of representative size, material, grade and weight shall be used as test pieces wherever possible.

1.9.7.2 Fabricated Assembly

Fabricated assembly shall be subjected to post weld heat treatment as required. Conduct fabricated assembly tests in accordance with ASME BPVC-IX-2012 and include yield strength, Charpy Impacts and hardness traverse. Conduct the hardness traverse test in accordance with ISO 15156 Part 2 to meet the stated maximum hardness criteria.

1.9.7.3 Other Welding

IRP Test pieces shall be actual parts or representative materials of equivalent mechanical properties and similar chemical composition.

IRP For other welding a similar process shall be adopted.

1.9.7.4 PQR Data

IRP The PQR should include the following data:

- MTR of test pieces
- Filler materials used
- Test results of fabricated assembly
- Yield, tensile, reduction in area, elongation
- Charpy Iimpacts
- Hardness traverse
- Bend test
- Welding variables
- Name of welder
- Shielding gas used
- Voltage/Amperage
- Welding speed
- Heat Input
- Record of pre-heat
- Record of interpass temperature
- Record of post-heat

1.9.8 Welder Qualifications

IRP The welder must be qualified to perform pressure welding (as per provincial regulations) and to the weld procedure. The effective duration of the welder's qualification is subject to provincial regulations.

1.9.9 Field Welding

IRP When field welding, the welder must ensure the following:

- Valid WPS and PQR are present.
- Valid welder qualifications are present.
- Electrodes are protected from dirt and moisture.
- Lighting is adequate if welding is performed in darkness (i.e. after sunset).
- Work area is adequately protected from the elements such as wind, moisture and dust.
- Visual examination of welding surfaces and surrounding areas shows no defects.
- Work pieces are cleaned and free of moisture, dirt and grease.
- Counter weights, ground clamps and other temporary attachments are not welded to the pipe or fittings
- Drilling fluid level is lowered to at least 600 mm below the weld line for casing bowls.

1.9.10 Pre-heat

IRP The pre-heat shall be applied to both pieces prior to welding (as per the WPS).

IRP A suitable heating method shall be used. Suitable methods provide

- the required metal temperature,
- uniform metal temperature increase and
- temperature control.

Electric resistance or thematic processes are preferred. Under controlled conditions the use of propane or oxyacetylene is also acceptable.

IRP Pre-heat temperature should be tested with a suitable method (e.g., crayons or thermocouple pyrometer) to ensure the required pre-heat temperature is obtained prior to welding and maintained during welding.

Casing bowls should be pre-heated immediately prior to welding to 230 °C (± 25 °C) for a minimum distance of 100 mm on either side of the weld area. Give special attention to the thicker sections of the casing bowl to ensure uniform pre-heating.

1.9.11 Interrupted Welding

IRP Interpass temperature shall be maintained on the work pieces (using adequate heat treatment) if welding is interrupted before completion.

Cover the work pieces with heat insulation blankets for controlled cooling if the interruption is for a prolonged period to ensure there are no detrimental effects to the materials.

Pre-heat temperature requirements must be met before welding resumes.

1.9.12 Post-heat

Post-heat is the application of heat to welded areas of the fabricated assembly at a specified temperature for a specified duration (in accordance with the WPS used) after all welding is complete.

IRP Weldment hardness shall be 22 HRC or less and the mechanical properties shall meet the design requirements as per the WPS.

IRP Post-heat weld temperature should be lower than part temper temperature. Minimum temperature shall be 565°C at one hour per 12 mm wall thickness (based on metallurgy of 4130) for the casing bowl. Higher temperatures (and shorter duration) can be used provided the temperature is below part temper temperature.

Post weld heat treatment must be performed with ceramic heating pads. A tiger torch will not meet temperature requirements.

Check the heat treatment temperature using a thermocouple pyrometer (or other suitable equipment) to ensure successful heat treatment.

Use hardness testing to confirm adequate stress relief of the assembly.

1.9.13 Repair Welds

IRP Repair welds shall be performed as follows:

- All repair welds shall be performed with the appropriate WPS.
- WPS selection shall be based on the material and mechanical properties of the part to be repaired.
- The welder shall be a qualified pressure welder and qualified to the selected WPS.

1.9.14 Product Hardness Test

IRP A surface hardness test shall be performed on the fabricated assembly after post-heat is completed. The requirements are as outlined in this section.

1.9.14.1 Location

Hardness tests shall be conducted

- at the weld metal,
- at the casing bowl heat-affected zone,
- at the casing heat-affected zone and
- on the parent metal unaffected by welding.

1.9.14.2 Procedure

Conduct the hardness test using ASTM E10 or ASTM E18.

Maximum hardness for carbon and low alloy steel shall be 22 HRC or 237 HB.

1.9.14.3 Documentation

Acceptance shall be based on the hardness recorded in the PQR if the weld is not accessible for hardness testing.

All hardness test results shall be recorded as part of the welding documentation and kept on file for the well.

1.9.15 Product Pressure Testing

IRP The fabricated assembly shall be pressure tested in accordance with appropriate codes governing the part.

1.9.16 Casing Bowl Pressure Test

IRP The casing bowl shall be pressure tested as follows:

- Test by internal pressure through the test port provided.
- Test pressures shall be the lower of 75 % of pipe collapse or burst and the rated working pressure of the top flange.
- Test media shall be nitrogen, hydraulic oil or media not subject to freezing.
- Test duration shall be 15 minutes for 2 cycles.
- The record of pressure test shall be part of welding record for the well.

Purge as much fluid as possible from the cavity after the test using compressed air or nitrogen.

1.9.17 Non-destructive Evaluation and Testing

IRP Each weld shall be subject to non-destructive testing.

IRP Fabrication of casing bowls to surface casing (after post weld heat treatment) shall be subjected to

- a visual examination (as per standard MSS SP55) of both weld joints,
- surface non-destructive evaluation (NDE) such as MPI or LPI and
- a hardness test of accessible weldment(s).

IRP Other weldments shall be subjected to non-destructive testing as required by API 6A. At a minimum, weldments shall be visually inspected to

- ensure welds are free of defects,
- verify dimensional accuracy,
- verify surface finish of weldment and
- ensure the weldment is free of undercut, pock marks, overlaps or cracks.

IRP Fabricated assemblies that are subject to cyclic loading must be examined by surface NDE such as MPI or LPI to ensure the weldment and heat affected zone are free of surface cracks. Acceptance criteria shall be per API 6A.

1.9.18 Welding Documentation

IRP Documentation of the welding and associated tests performed shall be recorded and filed for easy retrieval.

At a minimum the record shall contain:

- Name of welder
- Certificate number of welder qualification to perform pressure weld
- Certificate number of welder qualification to weld procedure
- Date of weldment
- Location of well
- WPS and PQR used
- Pre-heat temperature

- Post-heat time and temperature
- Hardness test record
- Pressure test record
- Non-destructive test results
- Name of person performing NDE
- Record of the repair of any defects found during examination of the welds

1.10 Drilling Fluids

1.10.1 Scope

The following key drilling fluid properties are discussed in this chapter:

- Drilling Fluid density
- H2S Scavenging Capacity
- Rheological Properties
- Alkalinity

The following key practices are included:

- Wellsite drilling fluid testing and monitoring.
- Equipment and material inventory requirements.
- Drilling Fluid Specialist requirements in the critical sour zone.

The recommended drilling fluid properties in this chapter should enable successful drilling of the critical sour zone. Variation from these properties may be required under specific circumstances based on recommendations from the Drilling Fluid Specialist on site.

Note: The recommendations in this chapter may be difficult to meet in a 100% oil-based drilling fluid system.

1.10.2 Drilling Fluid Density

IRP The drilling fluid must provide enough hydraulic head to prevent a kick.

For wells shallower than 1500 m, the minimum drilling fluid density should be 100 kg/m^3 higher than the density required to balance the estimated formation pressure.

For wells deeper than 1500 m, the drilling fluid density should provide a hydrostatic pressure a minimum of 1500 kPa higher (overbalance) than the estimated formation pressure.

Maintain the drilling fluid density immediately prior to entering the critical sour zone and while the critical sour zone is open.

A pressure mud balance should be on site to accurately measure the drilling fluid density.

IRP A 10 stand wiper trip should be made and bottoms up circulated prior to pulling out of the hole the first trip after penetrating the critical sour zone to ensure the correct amount of overbalance.

Additional wiper trips may be required depending on well conditions.

1.10.3 H_2S Scavenging

Scavenging is the removal of soluble sulphides in the drilling fluid by a chemical reaction. Many drilling fluid systems have natural H_2S scavenging capacity but measuring and maintaining the scavenging capacity is difficult so H_2S scavenging additives (H_2S Scavengers) must be used.

The initial addition of H_2S Scavengers (pre-treatment) is based on the calculated scavenging capacity of the chemical being used (as provided by the manufacturer). On-going treatment (maintenance) should be based on soluble sulphide monitoring.

IRP The drilling fluid should be pre-treated with enough H_2S Scavenger to provide a calculated scavenging capacity of 500 mg/l of soluble sulphides prior to entering the critical sour zone.

1.10.3.1 Soluble Sulphide Monitoring

IRP Whole drilling fluids (water and oil-based) should be monitored for soluble sulphides prior to entering the critical sour zone.

1.10.3.1.1 Hach Test

Hach tests apply to water-based drilling fluids and are typically conducted by the derrickman.

IRP Hach test procedures should be as follows:

- Start the test 12 hours prior to penetration of the critical sour zone and run every hour while circulating.
- Conduct Hach tests on bottoms up after trips or drilling breaks.
- Conduct Hach tests using whole drilling fluid until soluble sulphides are detected then switch to testing the filtrate or, preferably, Garrett Gas Train testing.
- Record the soluble sulphide content of the drilling fluid while drilling in the critical sour zone.

1.10.3.1.2 Garrett Gas Train Tests

Garret Gas Train tests normally apply to oil-based drilling fluids and are conducted by the Drilling Fluid Specialist.

IRP Garrett Gas Train test procedures should be as follows:

Pre-treatment

- Conduct Garrett Gas Train tests on the whole drilling fluid three times per tower per day or every time the drilling fluid density increases or decreases while in the critical sour zone.

While in the critical zone

- Conduct Garrett Gas Train tests every two hours if soluble sulphides are detected. Add H_2S Scavenger (as per 1.10.3.2 Maintenance) and continue monitoring every two hours. Revert to testing the whole drilling fluids three times per day when soluble sulphides are no longer detected.
- Record the soluble sulphide content of the drilling fluid while drilling in the critical sour zone.
- Conduct Garrett Gas Train tests on the filtrate when drilling with water-based fluids and the modified Garrett Gas Train test on the whole fluid when drilling with oil-based fluids.

1.10.3.2 Maintenance

IRP Scavenging treatment should be based on monitoring soluble sulphides in the filtrate for water-based drilling fluids and in the whole drilling fluid for oil-based drilling fluids.

Add an appropriate amount of H_2S Scavenger to remove soluble sulphides in the filtrate for water-based drilling fluids or the whole drilling fluid for oil-based drilling fluids. Monitor soluble sulphide levels as per 1.10.3.1 Soluble Sulphide Monitoring.

1.10.4 Rheological Properties

IRP Drilling fluid must be sufficiently viscous to suspend weighting material but not so viscous that it causes excessive swab/surge pressures.

Gel strengths are the best indicator for drilling fluid viscosity. Measure and record, at minimum, the 10 second and 10 minute gel strengths in combination with the Hach test or Garret Gas Train results. Begin measuring at least 30 minutes prior to penetration of the known critical sour zone and continue until the critical sour zone has been drilled through with all drilling fluid properties stabilized and no sour gas detection measured. Measurements (progressive or not) are determined by the rheology. Ten minute gel strengths should not exceed 30 Pa.

The drilling fluid type (oil or water-based) should also be considered because H_2S breakout varies depending on the fluid type.

While in the critical sour zone, the drilling fluid rheological properties should be maintained so that weight material remains suspended and circulation can be readily established after tripping. The Drilling Fluid Specialist on site must conduct the appropriate tests and subsequent drilling fluid adjustments to ensure these properties are maintained.

1.10.5 Alkalinity

IRP The drilling fluid must be sufficiently alkaline to suppress (buffer) the solubility of small amounts of H_2S in the wellbore.

1.10.5.1 pH Control

IRP The pH for water-based drilling fluids should be maintained at or above 10.5.

IRP Excess lime concentration in oil-based drilling fluids should be maintained above 20 kg/m^3.

1.10.5.2 pH Monitoring

pH monitoring applies to water-based drilling fluids while in the critical sour zone.

IRP A continuous pH monitoring system must be installed and located as close as possible to the flowline discharge of the drilling rig.

IRP The pH monitoring system must be equipped with an alarm to indicate a drop in pH level.

1.10.6 Equipment and Practices

1.10.6.1 Back-up Drilling Fluid Volumes

IRP The usable surface drilling fluid volume should be 100% of the calculated volume of a gauge hole less the drill string displacement while in the critical sour zone.

IRP Drilling should be stopped if circulation is lost and the 100% volume guideline cannot be maintained. Drilling should not resume until the guideline above can be met.

1.10.6.2 Drilling Fluid Mixing System

IRP A mechanical drilling fluid agitator should be placed in the suction tanks. Agitation should also be provided in other compartments.

IRP A minimum of two drilling fluid mixing systems (hopper, pump and piping) must be installed. Each system must be capable of mixing two sacks of

barite per minute (minimum 80kg/minute) and be independent of the drilling rig's circulating system.

Note: Consider a bulk delivery system (minimum 80 kg/minute) if high drilling fluid density is expected or drilling location dictates (i.e., remoteness and/or seasonal conditions).

IRP The rig's circulating system shall have a minimum of two mud pumps.

1.10.6.3 Material Inventory

IRP Material inventory levels on location should be as follows:

- Keep a minimum drilling fluid inventory to maintain the system to properties outlined in this IRP until the materials can be replenished from the nearest stock point.
- Keep enough inventory to weight up to the formation pressure plus the required overbalance (see 1.10.2 Drilling Fluid Density) if overpressure zones will be encountered and the formation pressure is known.
- Keep enough H_2S scavenger to provide the pre-treatment plus an additional calculated scavenging capacity of 500 mg/l soluble sulphides (see 1.10.3 H_2S Scavenging).
- Keep an inventory of lost circulation material (LCM) if lost circulation is expected or encountered.

1.10.6.4 Gas Detector

IRP A total gas detection unit shall be installed prior to entering the critical sour zone.

IRP The total gas detection unit shall be continuously monitored while in the critical sour zone (see 1.11.5.3 Mud-Gas Logging).

1.10.6.5 Drilling Fluid Specialist

IRP A Drilling Fluid Specialist shall be on site

- prior to penetration of the critical sour zone,
- while drilling through the critical sour zone,
- while drilling to at least 100 m below the critical sour zone and
- any time soluble sulphides are in the filtrate.

1.10.6.6 Suspension of Drilling Ahead

IRP Drilling and tripping should stop if the drilling fluid properties deviate from the recommendations of IRP 1. Condition the drilling fluid before proceeding.

IRP Drilling should stop if severe air or gas entrapment or serious foaming occurs. Alleviate the problem before proceeding.

1.11 Kick Detection

1.11.1 Scope

Kick detection equipment and procedures and well control training requirements are specified by regulatory bodies.

This chapter outlines the following additional kick detection equipment and practices required for a critical sour well:

- Drilling fluid volume measurement
- Drilling fluid return flow indicator
- Trip tank fluid volume measurement
- Measuring Indirect indicators
- Electronic drilling parameter measurement
- Driller's Instrumentation
- Mud-gas logging

1.11.2 Drilling Fluid Volume Measurement

IRP Each critical sour well shall have a drilling fluid tank level monitoring system (e.g., Pit Volume Totalizer). System requirements are as follows:

- The monitoring system must be sufficiently precise to detect a change of ±1.0m^3 in total pit volume. This typically means each active compartment must have a probe installed.
- A drilling fluid level monitoring station with an alarm system must be located at or near the driller's position.
- The alarm must activate before a volume change of ±2.0 m^3 during drilling operations.
- The alarm system must include a visual indicator which comes on automatically whenever the alarm is shut off. The indicator must effectively alert the drillers on the floor and in the doghouse (e.g. a highly visible flashing light).
- Mud tank volumes must be continuously recorded in the EDR (see 1.11.5.1 Electronic Drilling Recorder).

1.11.3 Flow Line Flow Sensors

IRP A flow line flow sensor shall be installed. Sensor specifications are as follows:

- The sensor must be sufficiently precise to detect a change of +10% in circulating rate and set an alarm when a change of 10% or greater is detected.
- The alarm must be located at or near the driller's position.
- Sensor data must be continuously recorded on the EDR (see 1.11.5.1 Electronic Drilling Recorder).
- The system must be checked once per tour while drilling. Check the system by changing the pump strokes per minute (SPM) by 10%, ensure the alarm sounds and note the corresponding flow reading. All sensor data will be recorded on the EDR (see 1.11.5.1 Electronic Drilling Recorder).
- The alarm system must include a visual indicator which comes on automatically whenever the alarm is shut off. The indicator must effectively alert the drillers on the floor and in the doghouse (e.g. a highly visible flashing light).

1.11.4 Trip Tanks

IRP A trip tank must be used. Trip tank specifications and operation are as follows:

- A level change of 25 mm equals a volume change of not more than 0.075 m^3. This equates to a maximum surface area of 3.0 m^2.
- The trip tank must have a minimum usable volume of 3.0 m^3.
- If the trip tank requires refilling during the trip, the tripping operation must be stopped while the tank is refilled.
- The hole-fill volume must be measured. Measure by manually gauging the trip tank or reading a mechanical or automated monitoring system visible at the driller's position.
- The monitoring board volume increments must be 0.1 m^3 for mechanical monitoring systems.
- The monitor's measurement increment must not exceed 0.0375 m^3 for electronic probes and the monitor must have readout to two decimal places.

1.11.5 Monitoring Indirect Indicators

1.11.5.1 Electronic Drilling Recorder

IRP An Electronic Drilling Recorder (EDR) should be used to record the following:

- Rate of penetration
- Standpipe pressure
- Flow rate
- Hook load
- Rotary table or top drive RPM

- Rotary table or top drive torque
- Pit volume
- Trip tank volume
- Mud return flow volume (flow-show)
- Casing annulus pressure (choke manifold casing pressure)

IRP EDR readouts must be at the doghouse, wellsite supervisor's office and rig manager's office.

IRP The primary EDR data recording and storage computer must be more than 25 m from the well centre.

IRP Records must be kept for the entire well and be available for inspection at the wellsite until rig release.

1.11.5.2 Driller's Instrumentation

IRP Driller's instrumentation must be as follows:

- The following indicators are required:
    - Hook load
    - Pump pressure and strokes per minute
    - Rotary table or top drive torque
    - Pit volume loss/gain
- All indicators must be visible from the driller's position.
- A cumulative pump stroke counter is required with readout at or near the driller's position. This counter might be included in the remote control system for a choke (if used). It may also be included in the EDR.

1.11.5.3 Mud-Gas Logging

IRP A manned mud-gas logging service should be used for continuous measurement of the gas content in the mud returns coming out of the flow line (see 1.10.6.4 Gas Detector).

IRP An alarm or intercom system should be in place to provide immediate communication between the mud-gas detector operator and the driller in case a sudden increase in mud-gas is noted.

1.12 Wellsite Safety

1.12.1 Scope

Safety personnel and adequate safety equipment for all workers must be on site during any drilling operation (as per appropriate regulations such as the Occupational Health and Safety Act and Regulations).

The recommendations in this chapter address the unique conditions associated with critical sour drilling operations.

1.12.2 General Safety Requirements

1.12.2.1 Pre-job Orientation

IRP A site-specific orientation must be presented to all on-site personnel involved in drilling before beginning any critical sour well work. Documentation supporting this orientation must be kept at the wellsite.

Orientation shall include, at minimum, the following topics for review and discussion:

- Potential hazards (e.g., pressures, H_2S percentage, etc.)
- Emergency preparedness
- Site specific equipment
- Communications
- Security
- Work status (critical or non-critical) and applicable responsibilities

1.12.2.2 H_2S Training

IRP All personnel on site while the critical sour zone is open must have the equivalent of H_2S Alive® certification.

Site access control personnel will deny access to any person without certification unless accompanied at all times by a guide with the required certification.

1.12.2.3 Safety Supervision

IRP An H_2S Safety Supervisor must be on site prior to drilling into the critical sour zone and remain on site at all times until the critical sour zone is isolated by cement meeting the specifications outlined in section 1.14.12 Casing and Liner Running.

IRP A minimum of two Safety Supervisors are required, with each on site for a maximum 12 hour shift, to cover any 24 hour period

The Safety Supervisor's role includes the following tasks:

- Monitor personnel compliance with established safety policy and guidelines
- Inspect and maintain safety equipment, monitors and breathing apparatus.
- Conduct inspections of safety equipment a minimum of twice per shift.
- Instruct personnel in the proper safety response to emergency situations, alarm conditions and gas-to-surface conditions.
- Instruct personnel in the use of breathing apparatus including safe mask-up procedures and equipment limitations.
- Conduct drills to practice the use of breathing apparatus.
- Familiarize personnel with designated safe briefing areas and the safety equipment in each area.
- Instruct personnel about safe evacuation from hazardous areas and supervise evacuations.
- Instruct wellsite personnel about
    - H_2S awareness,
    - site specific job hazards,
    - rescue procedures and
    - proper personal protective equipment usage.

1.12.2.4 Site Access Control

IRP Site access control must be in place prior to drilling into the critical sour zone. Site access procedures are as follows:

- Only authorized personnel are allowed on the wellsite.
- A record of all personnel on the wellsite must be kept and remain current at all times.
- The number of personnel on the wellsite during critical sour drilling operation should be kept to a minimum and restricted to only those directly involved in the operation.
- Visitors must be briefed on emergency procedures before entering the wellsite and their visit kept as short as possible.

1.12.2.5 Continuous H_2S Monitoring System

IRP A continuous H_2S/Lower Explosive Limit (LEL) gas detection system must be used while in the critical sour zone. The detection system requirements are as follows:

- Include a minimum of four sensors able to detect H_2S concentrations of 5 ppm or greater.
- Include audible and visual alarms near the driller's station.
- Set alarms at 10 ppm.
- Locate sensors at the shale shaker, near the bell nipple, on the rig floor and at the mud mixing unit.

IRP On-site personnel responsible for testing and maintenance of the system must be deemed qualified by the equipment provider.

1.12.2.6 Portable H_2S Detection Devices

IRP One portable H_2S detection device is required while drilling in the critical sour zone.

1.12.2.7 Breathing Air Equipment

IRP A compressed breathing system shall be on site while drilling the critical sour zone. The minimum basic equipment includes:

- 2400 cu. ft. Breathing air supply emergency preparedness
- 2 - Two-stage high pressure regulators
- 2 - Six-outlet air header assemblies
- 8 - Supplied air breathing apparatus complete with egress cylinders
- 8 - Self-contained breathing apparatus
- 8 - Spare 45 cu. ft. compressed breathing air cylinders
- 2 - 30 m x 10 mm ID special hose c/w quick couplers
- 6 - 30 m x 6 mm ID special hose c/w quick couplers
- 1 - 610 mm x 760 mm H_2S warning sign on tripod
- 2 - Wind direction indicators

IRP The safety equipment must be installed and ready for service and crew members trained in the use of the equipment prior to drilling into the critical sour zone.

1.13 Wellsite Personnel

1.13.1 Scope

The wellsite personnel recommended practices address the following:

- Operator and rig contractor responsibilities
- Supervisory and crew requirements
- Supervisory and crew qualifications, training and certification

The certification and training courses in this chapter refer to courses offered by Enform or sanctioned equivalents.

1.13.2 Roles and Responsibilities

1.13.2.1 Operator's Representative

IRP The operator must designate a Primary Wellsite Supervisor with overall responsibility to the operator for the well.

IRP The Primary Wellsite Supervisor must be on site or readily available (i.e., can get to the location within two hours) at all times.

The Primary Wellsite Supervisor

- has overall control in the chain of command,
- establishes the chain of command and communication line at the wellsite and
- is responsible for his/her company's regulatory compliance in the operation of the well.

1.13.2.2 Rig Contractor's Representative

IRP The rig contractor must designate a representative to be responsible for rig operation during drilling.

The rig contractor's representative is responsible to the operator's representative for operation of that well. This provides a single chain of comment for well operations.

The rig contractor's representative is responsible to his/her company for the rig equipment, crew and regulatory compliance in the rig operation.

1.13.2.3 Shared Responsibility

The responsibility for day-to-day operations on a wellsite is shared between the contractor and operator representatives.

1.13.3 Supervision and Crew Requirements

IRP A 24-hour operation must have a minimum of two supervisors (including the primary supervisor) for a maximum of 12 hours each. More supervisors may be added if desired.

IRP Each shift must have a minimum five man rig crew while in the critical sour zone.

1.13.4 Minimum Qualifications

The demands placed on the operator's office supervisors (e.g., superintendents) of a critical sour drilling operation are very high due to the inherently complex nature of the operation, the increased risk factor and the potential impact to the public. Office supervisors must have the technical, organizational and operational competence to meet these demands.

In this section, experience in the sour zone means operational experience on any well where an H_2S interval is drilled through. It does not mean critical sour wells.

1.13.4.1 Primary Wellsite Supervisor

IRP The Primary Wellsite Supervisor must be competent in the application of Industry Recommended Practices and Emergency Response Planning.

IRP The Primary Wellsite Supervisor must have the following minimum experience:

1. Five years operator's wellsite supervisory experience or three years drilling engineering plus two years wellsite supervisory experience.
2. Supervised a minimum of five sour drilling operations while operations were conducted in the sour zone.

Note: The Primary Wellsite Supervisor's previous sour well experience must be on wells of similar complexity and depth as the critical sour drilling operation they will be supervising.

IRP The Primary Wellsite Supervisor must have the following training and certifications:

- IRP 7 Standards for Wellsite Supervision of Drilling, Completions and Workovers, Section 7.6.3 Training Requirements
- Second Line BOP

- H_2S Alive®
- First Aid
- WHMIS
- TDG
- Confined Space Entry (Pre-Entry portion only)

IRP The Primary Wellsite Supervisor must be prepared to substantiate his/her work history. Time forward work is to be logged by the supervisor and supported by his/her direct supervisor of the operating company.

1.13.4.2 Secondary Wellsite Supervisor(s)

IRP The Secondary Wellsite Supervisor(s) must have the following minimum experience:

1. Three years wellsite supervisory experience (operator or rig contractor) or three years drilling engineering experience.
2. Supervised a minimum of two sour drilling operations while operations were conducted in the sour zone.

IRP The Secondary Wellsite Supervisor must have the following training and certifications:

- IRP 7 Standards for Wellsite Supervision of Drilling, Completions and Workovers, Section 7.6.3 Training Requirements
- Second Line BOP
- H_2S Alive®
- First Aid
- WHMIS
- TDG
- Confined Space Entry (Pre-Entry portion only)

IRP The Secondary Wellsite Supervisor must be prepared to substantiate his/her work history. Time forward work is to be logged by the supervisor and supported by his/her direct supervisor of the operating company.

1.13.4.3 Rig Manager

IRP The Rig Manager must have the following minimum experience:

1. Five years of experience as a rig manager or driller.
2. Been involved in (as a rig manager or driller) a minimum of five drilling operations while operations were conducted in the sour zone.

IRP The Rig Manager must have the following training and certifications:

- Second Line BOP
- H_2S Alive®
- First Aid
- WHMIS
- TDG
- Confined Space Entry
- Fall Protection

1.13.4.4 Drilling Rig Crew

IRP The operator and contractor must work together to ensure to ensure drilling rig crew competency in critical sour well drilling. Specific crew member experience and certifications are as follows:

- The drillers, derrickman and motorman for all rig crews should have experience with sour well operations.
- All members of the drilling rig crew must demonstrate competency in BOP and man down drills as per 1.14.4 BOP Drills and 1.14.5 Man Down Drills.

IRP The drilling crew must have the following training and certifications:

- H_2S Alive®
- First Aid
- WHMIS
- Confined Space Entry (minimum two crew members)
- Fall Protection (Driller and Derrickman)

1.13.4.5 Safety Specialist

IRP The Safety Specialist must have a minimum of two years as a field safety specialist with experience in sour well operations.

IRP The Safety Specialist must have the following training and certifications:

- H_2S Alive®
- First Aid
- WHMIS
- TDG
- Confined Space Entry
- Fall Protection

1.14 Practices

1.14.1 Scope

This chapter discusses the following practices:

- Rig inspections
- BOP, casing and choke manifold pressure testing
- BOP drills
- Tripping
- Drillstem testing
- Directional surveying
- Coring
- Fishing operations
- Logging
- Casing and/or liner running and cementing

1.14.2 Rig Inspections

IRP Detailed rig inspections shall be conducted

1. prior to drilling out the surface casing,
2. prior to drilling out the intermediate casing and
3. within the 24 hour period prior to penetration of the critical sour zone.

Note 1: Inspection 3 would coincide with inspection 2 if the intermediate casing is set immediately above the critical sour zone.

Note 2: The operator must notify the appropriate government agency 48 hours prior to the above inspections.

IRP The operator and contractor shall conduct weekly detailed rig inspections during drilling.

IRP All inspections shall use an inspection check sheet. Each inspection check sheet is to be dated and signed by the operator's wellsite supervisor and the rig manager and filed on site.

1.14.3 Pressure Testing

1.14.3.1 BOP Pressure Testing

IRP The BOPs shall be pressure tested prior to drilling out surface casing, prior to drilling out any subsequent casing strings and at minimum every 30 days while in the critical sour zone.

The pressure test shall be as per relevant government regulations and 1.5.12.3 Pressure Testing).

1.14.3.2 Casing Pressure Testing

IRP The intermediate casing shall be pressure tested prior to drilling out.

IRP Casing integrity shall be evaluated, either through a pressure test or appropriate casing wear log, at minimum every 30 days.

> **Note:** Consider more frequent casing integrity evaluations if well conditions indicate excessive casing wear (e.g., high dog legs, rig misalignment, wear on wear busing, metal contamination in drilling fluids, etc.).

1.14.3.3 Choke Manifold Pressure Testing

IRP The choke manifold shall be pressure tested prior to drilling out surface casing, prior to drilling out any subsequent casing strings and after every use.

The pressure test shall be as per relevant government regulations and 1.6.9.2 Pressure Testing).

1.14.4 BOP Drills

IRP Each driller and crew member must have an adequate understanding of the correct operation of all kick detection and monitoring equipment prior to drilling into the critical sour zone.

IRP Each driller and crew member must understand their well control duties for kick control during drilling, tripping and out of the hole.

IRP **Detailed BOP drills shall be conducted for each rig crew and the results documented. Crew competence must be demonstrated prior to penetrating the critical sour zone. BOP drills shall be conducted**

1. prior to drilling out the surface casing,
2. prior to drilling out the intermediate casing or prior to penetrating the critical sour zone and
3. at least twice per week while in the critical sour zone.

1.14.5 Man Down Drills

IRP **Man down drills shall be conducted for each rig crew and the results documented. Crew competence must be demonstrated prior to penetrating the critical sour zone. Man down drill shall be conducted**

1. prior to drilling out the intermediate casing or prior to penetrating the critical sour zone and
2. at least twice per week while in the critical sour zone.

1.14.6 Tripping Practices

1.14.6.1 Trip Supervision

IRP **Each trip while in the critical sour zone must be pre-planned by the operator's wellsite supervisor and a pre-job safety meeting held with each crew participating in the trip.**

IRP **A wellsite supervisor or rig manager with a Second Line BOP certification must be on duty during all trips while in the critical sour zone.**

1.14.6.2 Hole Fill

IRP **The hole must be filled to surface after every 15 singles (maximum) of drill pipe are pulled and after every 3 singles (maximum) of drill collars are pulled.**

IRP Weighted pills should be used to ensure the pipe pulls dry.

IRP **The practice of leaving the drilling fluid level partially down the annulus in order to pull dry pipe shall not be used.**

1.14.6.3 Trip Record

IRP A trip record must be made for every trip during the drilling of the well. Each trip record must include the following:

- Operator's wellsite supervisor and contractor's rig manager signatures and date signed.
- Actual volume required each time the hole is filled (as per 1.14.6.2 Hole Fill).
- Actual cumulative fill volume after each successive fill.
- Theoretical volume required each time the whole is filled.
- Theoretical cumulative fill volume.

1.14.6.4 Flow Checks

IRP Flow checks should be performed whenever any of the direct or indirect kick indicators are evident. The well should be observed for 5 to 15 minutes to see if any flow occurs. Consider rotating the string slowly during this observation time.

IRP Flow checks should be conducted as follows:

- Tripping out.
  - After pulling five percent of the drill pipe.
  - At the mid-point depth of the wellbore.
  - Prior to pulling the first stand of drill collars.
  - When the drill string is out of hole.
- Tripping in.
  - Upon reaching the surface casing point.
  - At the mid-point depth of the wellbore.

IRP The depth and time of all flow checks should be recorded in the tour book.

IRP A 10 stand wiper trip should be made and bottoms up circulated prior to pulling out of the hole the first trip after penetrating the critical sour zone to ensure the correct amount of overbalance (as per 1.10.2 Drilling Fluid Density).

1.14.7 Drillstem Testing

IRP Critical sour zones shall not be drillstem tested.

1.14.8 Directional Surveying

IRP The wellbore location must be known in order to drill a relief well.

Recommendations for determining location are as follows:

- Maximum lateral uncertainty should be no greater than +/-30 m at 2 Sigma (approximately 95% confidence level).
- Wellbore uncertainties should be calculated using International Steering Committee for Wellbore Survey Accuracy (ISCWSA) sanctioned error models and survey instrument performance models (IPM).
- Survey frequency during drilling should be adequate to ensure the calculated well path is maintained within the operator's defined target parameters and to meet regulatory requirements (maximum interval of 150 m if inclination is < 3°).
    - A maximum survey interval of 30 m is recommended if the well is vertical or in a tangent section.
    - A maximum survey interval of 10 m is recommended if the well is changing angle (build, drop or turn) to better define the actual well path.
- Wellbore uncertainty should be calculated based on the drilling surveys and survey tools used prior to entering the critical sour zone. If the positional uncertainty is >30 m a higher quality survey tool (e.g., multi-shot magnetic survey, gyro survey, etc.) should be run to better define the well position and reduce positional uncertainty.

1.14.9 Coring

IRP The following practices shall apply to coring in the critical sour zone:

- Penetration of the upper porous interface prior to coring is advised. If the interface must be cored then the ability to circulate above the core barrel must be available (e.g., a ported string).
- After tripping in the core barrel, bottoms up must be circulated and the wellbore confirmed dead prior to coring.
- After coring, a 10 stand wiper trip should be made and bottoms up circulated prior to pulling out of the hole for the core barrel.

1.14.10 Fishing Operations

IRP A full hazard and operability review with fishing and wireline representatives should be conducted prior to fishing operations.

1.14.10.1 Downhole Floats

For normal (non-fishing) drilling operations downhole floats are recommended (see 1.8.10 Downhole Floats). However, for most trips made during fishing operations this option is not available due to fishing tool requirements.

IRP Procedures for trips during fishing operations should be as follows:

- Always circulate at least one bottoms up before tripping out.
- Use extra diligence on tripping procedures (flow checks, hole fill, reduced tripping speed).
- Ensure crews can competently install the stabbing valve.
- Consider running a profile sub to provide the option to set a back pressure float or plug.
- Test the system for pressure integrity (recognizing that in some configurations it may not be possible to test all connections).
- Properly secure all system components to prevent excessive movement.

1.14.10.2 Through Drill Pipe Wireline Operations

IRP A lubricator and associated bleed-off system shall be used while running wireline tools inside drill pipe.

IRP All piping, valves, hoses and manifolds should have pressure ratings checked and materials must be suitable for sour service (as per 1.6 Choke Manifold).

IRP The complete system should be pressure rated to at least the working pressure of the BOP stack.

1.14.10.3 Retrieving Open Hole Logging Tools

IRP The cut and thread technique should not be used for retrieving stuck open hole logging tools.

1.14.11 Logging

IRP The procedures for logging shall be as follows:

- The wellbore shall be free of formation fluids and confirmed to be in an overbalanced condition prior to any open hole logging operations. A wiper trip (as per 1.10.2 Drilling Fluid Density) may be warranted.
- A logging job pre-plan review should be conducted with the logging contractor to identify any potential issues. Consider using a lubricator (as per 1.14.10.2 Through Drill Pipe Wireline Operations).
- The wireline and tools should be treated with an appropriate inhibitor.

- The hole must be continuously monitored for any indications of flow.
- The pipe to logging tool connector shall be sour service material for drill pipe conveyed logging.

1.14.12 Casing and Liner Running

IRP The procedures for casing and liner running should be as follows:

- The wellbore shall be free of formation fluids and confirmed to be in an overbalanced condition prior to running casing or liner across the critical sour zone. A wiper trip may be warranted (as per 1.10.2 Drilling Fluid Density).
- Casing/liner running and cementing job pre-plan reviews should be conducted based on current well conditions to confirm or, if necessary, revise the original plan.
- After running and cementing casing and prior to removing the BOPs, one of the following should be done:

  1. the casing primary seal must be energized (i.e., run through the BOP) and/or
  2. the cement across the critical sour zone must achieve 50 psi compressive strength as per section 4.6.3 of API Standard 65 Part 2 Isolating Potential Flow Zones During Well Construction, Second Edition. December 2010

- After running and cementing a liner and prior to removing the BOPs, the pressure integrity of the liner lap should be tested. The casing should be cleaned to the top of the liner and a positive or negative pressure test conducted.
- Consider changing BOP rams to casing rams (depending on casing design). The appropriate crossovers from casing to drill pipe must be readily available if casing rams are not used.

1.14.13 Reviews and Safety Meetings

1.14.13.1 Pre-Job Safety Meeting

IRP A pre-job safety meeting must be conducted with all personnel who will be on site during critical drilling operations immediately prior to starting critical sour drilling operations. The meeting should include a review of the project plan.

1.14.13.2 Emergency Response Plan Meeting

IRP An Emergency Response Plan meeting to review the ERP must be conducted with all personnel involved with the ERP immediately prior to drilling into the potential sour zones. The operator, operator's contractors, regulatory agency representatives, government representatives and representatives of any agencies listed in the ERP should attend.

1.14.13.3 Safety and Operational Meetings

IRP When in the critical sour zone, a short meeting must be conducted to review upcoming operations

1. prior to each shift or crew change and
2. prior to a significant change in operations (e.g., tripping, logging, etc.).

IRP The meeting should include all personnel on location and be documented on the tour sheet.

1.14.14 Wear Bushing

IRP Wear bushings must be run to prevent significant wear in the BOP and wellhead area. Bushings should be checked prior to entering the critical sour zone. Wear bushings may be run through the BOP without removal of the drill string for inspection purposes.

Appendix A: Document History

ARP 1 to IRP 1 Conversion

The following table summarizes the sections in the ARP and the corresponding section in the IRP.

Table 21. ARP 1 vs. IRP 1

	ARP 1		IRP 1
1.0	Scope and Contents	1.1 1.2	Preface Hazard Assessment
2.2	Blowout Preventer Stack	1.5	Blowout Preventer Stack
1.2	Drill Pipe Design and Metallurgy	1.8	Drill String Design and Metallurgy
1.3	Mud – Gas Separators	1.7	Mud – Gas Separators
1.4	Choke Manifolds	1.6	Choke Manifold
1.5	Auxiliary Equipment	1.8	Drill String Design and Metallurgy
1.6	Sour Service Casing	1.4	Casing Design and Metallurgy
1.7	Mud System Design	1.10	Drilling Fluids
1.8	Kick Detection	1.11	Kick Detection Equipment
1.9	H_2S Detection	1.11	Kick Detection Equipment
1.10	H_2S Monitoring	1.12	Wellsite Safety
1.11	Rig Inspection	1.14	Practices
1.12	Wellsite Supervision	1.13	Wellsite Personnel
1.13	Information Exchange	1.3	Planning
1.14	Human Factors	1.13	Wellsite Personnel
1.15	Welding Guidelines	1.9	Welding

2003 Revisions

The revisions in this section identify the section, table or clause as existed in the 2003 version of the document. During the review and reformat to the new style guide in 2013 some of the section numbers may have been revised.

Table 22. 2003 Revisions

Section	Description
Editing and Typos	During the use of IRP 1 through 2002 and 2003, a few editing and typographical errors were noted and revised.
Section 1.4 Casing Design and Metallurgy	Malcolm Hay, Shell Canada Ltd and Dan Belczewski, Bissett Resource Consultants Ltd revised this section
Table 1.4.7.1	• L80 type 1 column, Manganese line: Add footnote (2) beside 1.20; (i.e., change to 1.202) • C90 type 1 column, Carbon line: typographical error, (i.e., change to 0.32) • T95 type 1 column, Carbon line: Add footnote (3) beside 0.30; (i.e., change to 0.303)
Clause 1.4.11.1	Fourth paragraph, Change to read as follows: SSC testing of casing and couplings for critical sour gas service shall be performed in solution A.
Clause 1.4.15.1	Add HIC Testing Requirements protocols and data.
Table 1.8.6.3	Under Grade Maximum Average – column SS105 change 27.0 to 28.0.
Section 1.9 Welding	The following task group reviewed entire section: • Chris Chan, ABB Vetco Gray Canada Inc. (leader) • Malcolm Hay, Shell Canada Ltd • Dan Belczewski, Bissett Resource Consultants Ltd

2014 Revisions

General Revisions

The 2014 review of IRP 1 involved reformatting the entire document to the new DACC Style Guide and updates to the content of several sections. There were IRP statements created in the new format (which were previously in the subheadings). References were added to the beginning of many segments and references were updated to current versions. The updates are too numerous to document in detail but the key changes are outlined below.

Table 23. 2014 Revisions

Section	Description
Editing and Typos	
1.0 Preface	New section with information pulled from previous section 1.1 Acknowledgments and Scope
1.1 Background and References	New section added to explain why the document was created and explain how the references are used throughout

Section	Description
1.2 Hazard Assessment	Removed references to Blow and removed the diagrams
1.3 Planning	Moved well types to 1.1 Background and References
1.4 Casing Design and Metallurgy	Added grade C110 throughout section, removed wellhead vs. bottomhole pressure diagram and replaced qualified technical expert with an engineering assessment.
1.5 Blowout Preventer Stack	Updated with information about BOP side outlets, new diagrams for configurations.
1.6 Choke Manifold	Minor corrections.
1.7 Mud-Gas Separators	Minor corrections and reorganization for clarity.
1.8 Drill String Design and Metallurgy	Removed references to pipe grades no longer permitted for sour service (see Section 1.8 Drill String Design and Metallurgy History below). Updates to prequalification.
1.9 Welding	Minor corrections by Chris C.
1.10 Drilling Fluids	Updates to the Scavenging section for clarity.
1.11 Kick Detection	Minor updates for consistency with AER Directive 36.
1.12 Wellsite Safety	Formatting updates only.
1.13 Wellsite Personnel	Formatting update and updates to crew requirements.
1.14 Practices	Formatting updates only.

Section 1.8 Drill String Design and Metallurgy History

As of the 2013 Edition of IRP 1, the following drill pipe grades are no longer permitted for use in critical sour operations:

1. API Grades E75, X95, G105 and S135.
2. Hardness Tested (as specified in this IRP) API E,X,G (referred to as HE, HX and HG).

The entire clause dealing with hardness testing of API Grades (1.6 Hardness tested API Grade Drill Pipe Specifications) was removed. The original contents are noted below for historical purposes.

1.6 Hardness Tested API Grade Drill Pipe Specifications

1.6.1 IRP Hardness Tested Grade Drill Pipe Specification: HE, HX, HG

All API E, X and G drill pipe not manufactured to SS specification, and without previous hardness documentation, must be evaluated for hardness level prior to initial use for critical sour gas drilling.

Hardness testing must be redone after any significant re-work (e.g., baking after H2S exposure or tool joint rebuild).

Hardness testing will conform to API RP 5A5 Subsection 4.5 with the following additional requirements:

- A Direct reading Rockwell "C" (HRC) scale is required for the drill pipe.
- Rockwell "C", Brinell, or Equotip devices are satisfactory for the tool joints.
- A total of nine impressions per joint required; three each at the box, pin and mid tube. Hard banding, heat-affected zones and areas of cold working such as slip and tong marks should be avoided.
- Abnormally high readings should be confirmed with additional tests on the prepared surface. Readings less than HRC 20 will not normally require retesting.

Each joint passing the hardness criteria will be marked with a unique identifier, which avoids duplication within a pipe owner's stock.

Table 1.8.5 – API Drill Pipe Hardness Maximum Hardness (Rockwell “C”) For HE, HX, and HG Drill Pipe

API Grade	**Box**	**Pin**	**Tube**
HE 75	38	38	27
HX 95	38	38	30
HG 105	38	38	32

Documentation and Reports:

Hardness inspection reports will include the following details:

- location, rig, and pipe owner
- inspection company, date(s), and inspector
- diameter, weight, grade, connection type, and pipe classification
- test equipment make and model
- calibration details each occurrence
- surface preparation technique (light filing or sanding)
- individual and average readings for pin, tube, and box for each joint
- summary indicating total number of joints inspected, total rejected, and rejection criteria

Appendix B: Heavy Weight Drill Pipe

Heavy Weight Drill Pipe (HWDP) shall meet the following requirements if it is below the mud return line near the surface or above the last drill pipe above the bottomhole assembly (BHA). In this region, exposure to an H_2S environment could make HWDP susceptible to Sulfide Stress Cracking (SSC). Outside of this region HWDP is not exposed to an environment leading to this type of phenomenon.

HWDP is a component of the drill string that is used to provide a heavier component with flexibility between drill pipe and drill collars. It is provided in lengths equal to drill pipe. HWDP can be used in the BHA as a transition between the drill pipe and drill collars. It can also be used in the vertical section to add weight and push the string around a kick off point

HWDP is either made as an integral (one piece) design or a friction welded (multi-piece) design. This section will discuss requirements for both.

Integral HWDP

Integral HWDP is made from one piece of material (bar from a continuous casting process) and typically has the same ID as the ID of the pin connection thus resulting in a thick wall section.

Tensile Specifications

Tensile specifications for integral HWDP shall be as follows:

- Testing frequency shall be a minimum of one per heat per lot.
- Tensile test shall meet the limits in the table below.

Table 24. Integral HWDP Tensile Specifications

Bar OD	Yield Strength (MPa/ksi)		Ultimate Tensile Strength (MPa/ksi)		Elongation	Reduction in Area
	Minimum	Maximum	Minimum	Maximum	Minimum	Minimum
≤ 7 in.	758 / 110	862 / 125	862 / 125	1000 / 145	13%	35%
> 7 in.	689 / 100	862 / 125	862 / 125	1000 / 145	13%	35%

Hardness Specifications

Hardness specifications for integral HWDP shall be as follows:

- Testing frequency shall be on each bar used to manufacture the components.
- The hardness test shall be on the outside diameter of the bar or tube using Brinell hardness (Rockwell C acceptable alternative) test methods in compliance with ASTM A 370 requirements.
- Hardness specification for these components shall be limited to a maximum hardness of HRC 37.0.

Toughness Specification

Toughness specifications for integral HWDP shall be as follows:

- Testing frequency shall be a minimum of one test per heat per heat treat lot.
- Toughness specification shall be a minimum average longitudinal Charpy "V" notch impact value of 68 joules (50 ft-lbf.) and a minimum single of 54 joules (40 ft-lbf) for a standard full size specimen at room temperature (as per ASTM E23 98).

H_2S Resistance Specification

Resistance specifications for integral HWDP shall be as follows:

- Testing frequency shall be a minimum of one test per heat per heat treat lot.
- H_2S resistance specification shall include a demonstrated minimum threshold of 493 MPa / 72 ksi (65% of minimum specified minimum yield strength) for 720 hours per NACE TM-01-77, Method A using Test Solution A.
- To be acceptable, any heat / heat treat lot with a failed specimen requires two additional specimens with no failures.

Chemistry Recommendation

The recommended chemistry for integral HWDP is shown in the table below.

Table 25. Integral HWDP Chemistry Recommendation

	% by Weight	
	Minimum	**Maximum**
Carbon	0.25	0.44
Manganese	-	1.00
Chromium	0.70	1.40
Molybdenum	0.40	0.70
Sulphur	-	0.010
Phosphorous	-	0.015

Alternative chemistries are acceptable but the component must meet all of the requirements of Integral HWDP as noted in the previous sections.

Transformation and Grain Size

Transformation and grain size requirements shall be as follows:

- Testing frequency shall be a minimum of one test per heat per heat treat lot.
- The material shall have a minimum transformation to martensite after quenching of 90% across the full wall of the thickest section.
- Grain size shall be six or finer (as per ASTM E112 92).

Hard Banding Specification

Hard banding specifications shall be as per the recommendations for tool joints in 1.8.8.9 Hard Banding.

Welded HWDP

Welded HWDP is welded using either the same process as the process used for the manufacture of drill pipe (tool joint machined out of forging) or by welding a tool joint machined out of bar.

Welded HWDP Tube Section

The HWDP tubes shall meet NACE MR0175/ISO 15156 revision 2009 Section 3 for Carbon and Low–Alloy Steels and Cast Irons. There is no H_2S resistance test required.

Welded HWDP Tube Section Tensile Specifications

The table below outlines the tensile properties for welded HWDP tube.

Table 26. Welded HWDP Tensile Specifications

Yield Strength (MPa/ksi)		Ultimate Tensile Strength (MPa/ksi)		Elongation	Reduction in Area
Minimum	Maximum	Minimum	Maximum	Minimum	Minimum
380 / 55	-	655 / 95	-	18%	-

Welded HWDP Tube Section Hardness Specifications

The hardness specifications for welded HWDP tube sections shall be as follows:

- Testing frequency shall be a minimum of one test traverse per heat per heat treat lot.
- A test traverse shall consist of full length hardness traverses mid-wall, near inner and outer surfaces on longitudinal strip type cross section sample.

- Hardness Testing shall conform to ASTM A370.
- Hardness specification for these components shall be limited to a hardness of HRC 22. Individual hardness readings exceeding this value are permitted if the average of the close proximity readings does not exceed HRC 22 and no single reading exceeds HRC 24.
- Other test methods may be used but conversion shall be made in accordance with ASME E 140.

Welded HWDP Tube Section Toughness Specifications

The toughness specifications for welded HWDP tube sections shall be as follows:

- Testing frequency shall be a minimum of one test per heat per heat treat lot.
- Toughness specification shall be a minimum average longitudinal Charpy "V" notch impact value of 42 joules (31 ft-lbf) for a standard full size specimen at room temperature, per ASTM A370 with no single value below 32 joules (23 ft-lbf).

Welded HWDP Tube Section Chemistry Recommendation

The recommended chemistry for welded HWDP tube sections is shown in the table below.

Table 27. Integral HWDP Chemistry Recommendation

	% by Weight	
	Minimum	**Maximum**
Carbon	0.38	0.43
Manganese	-	0.10
Chromium	-	0.10
Molybdenum	0.40	0.70
Sulphur	-	0.017
Phosphorous	-	0.020

Alternative chemistries are acceptable but the tube must meet all of the requirements of welded HWDP Tube Sections as noted in the previous sections.

Welded HWDP Tool Joint

The requirements for welded HWDP tool joints are as follows:

- If forging material: shall meet all requirements of 1.8.8 SS Grade Tool Joint Specification.
- If made of bar: shall meet all requirements of Integral HWDP as noted above.

Welded HWDP Weld Zone

The weld zone between the tool joint and the tube shall meet the same requirements as the weld zone of drill pipe as per 1.8.8.5 Toughness Specifications.

Each weld zone shall be hardness tested in the heat affected zone to demonstrate the surface hardness of the weld zone is less than 37 HRC. The hardness testing method is at the discretion of the manufacturer.

Field Inspection of HWDP

Heavy Weight Drill Pipe shall be inspected as per API RP7G-2.

Frequency, documentation and reports shall be as per drill pipe in 1.8.9 Inspection.