COMPLETING AND SERVICING
CRITICAL SOUR WELLS

INDUSTRY RECOMMENDED
PRACTICE (IRP)

VOLUME 2 - 2006

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2.0 SCOPE AND CONTENTS

2.0.1 ACKNOWLEDGEMENT

This Industry Recommended Practice (IRP) under the auspices of the Drilling and Completions Committee (DACC), was originally developed as an Alberta Recommended Practice (ARP) by the Blowout Prevention Well Servicing Committee (BPWSC), and subsequently updated by the Well Services Review Committee in 2003.

Acknowledgement of the following individuals is in recognition of their time and effort in any and all of the meetings and work sessions, and acknowledgement of the corporate entities that allowed these individuals to take time away from their busy desks to help complete this project.

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Russell Nelson (CAPP) Shell Canada
2.0.2 DISCLAIMER

This Industry Recommended Practice (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 standards for completing and servicing critical sour wells.

This IRP was developed under the auspices of the Drilling and Completions Committee (DACC), a joint industry/government committee established to develop safe, efficient and environmentally suitable operating practices for the Canadian Oil & Gas industry in the areas of drilling, completions and servicing of wells. The primary effort is the development of IRPs with priority given to:

- Development of new IRPs where non-existent procedures result in issues because of inconsistent operating practices.
- Review and revision of outdated IRPs particularly where new technology requires new operating procedures.
- Provide general support to foster development of non-IRP industry operating practices that have current application to a limited number of stakeholders.

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

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

Every effort has been made to ensure the accuracy and reliability of the data and recommendations contained in the IRP. However, DACC, its subcommittees, and individual contributors make no representation, warranty, or guarantee in connection with the publication or the contents of any IRP recommendation, and hereby disclaim liability of responsibility for loss or damage resulting from the use of this IRP, or for any violation of any legislative requirements.
This IRP has been sanctioned (reviewed and supported the IRP as a compilation of best practices) by the following organizations:

Alberta Energy and Utilities Board  
Alberta Human Resources and Employment  
British Columbia Oil & Gas Commission  
British Columbia Workers Compensation Board  
Canadian Association of Oilwell Drilling Contractors  
Canadian Association of Petroleum Producers  
Intervention and Coil Tubing Association  
Manitoba Energy and Mines  
National Energy Board  
N W Territories & Nunavut Workers Compensation Board  
Petroleum Services Association of Canada  
Saskatchewan Energy & Mines  
Saskatchewan Labour  
Small Explorers and Producers Association of Canada

2.0.3 Introduction

This Industry Recommended Practice (IRP) is a continuation of a series of IRPs that have been developed over the years for the drilling and completions industry. The mandate was to develop recommended practices to enhance safe completing and servicing operations of critical sour wells.

The recommendations set out in this IRP were developed from existing documentation and current applicable provincial regulations of British Columbia, Alberta and Saskatchewan.

The recommendations were derived with the safety of on-site personnel and the public and the protection of the environment as a priority consideration. The operator is responsible to ensure these issues are addressed adequately.
2.0.4 Scope

The purpose of this IRP is to enhance safe operations by providing information and recommendations for the completing and servicing of critical sour wells.

The Wellhead section addresses the installation, operation and maintenance of wellheads and wellhead related equipment during initial completions, re-completions, or subsequent production operations of critical sour gas or oil wells.

The service rig BOP Equipment section addresses the surface BOP equipment, including BOP stack configuration, manifolding, accumulator, tubing safety valve, heating of equipment, quality assurance, and installation and operation.

Downhole Equipment is installed in producing critical sour wells to enhance production and/or provide additional well security. The downhole equipment section focuses attention on those procedures which may affect the security of the well. The number of tools available are too diversified to be individually addressed and have been grouped into commonly recognized categories, such as packers, nipples, safety valves, etc.

The Tubular Goods section includes recommendations that will reduce the probability of an uncontrolled flow of H$_2$S in a critical sour well. A tubing failure alone will not directly result in an uncontrolled flow, but will result in a workover operation. During this operation, the risk of an uncontrolled flow increases, and is the focus of the recommendations.

The Fluids and Circulating System section addresses the minimum acceptable standards for equipment and completion/servicing fluids for well control and fluid handling on critical sour wells.

The Electrical Wireline (braided wireline) operations section includes recommendations regarding the equipment integrity during completing/servicing operations which forms an integral part of the pressure control equipment directly attached to the BOP stack or wellhead.

Key issues relating to Slickline equipment requirements include rigging in procedures, pressure testing, equipment servicing and reporting, technical information relating to mechanical properties and strengths, and operational considerations associated with the equipment.
The primary purpose of snubbing is for conducting servicing or completions operations on a live well with or without the wellhead removed. When the wellhead is removed it is necessary to install an appropriate well servicing BOP stack on the casing head prior to installing the snubbing stack. The Snubbing section addresses rigging up, pressure testing, equipment configuration, material and elastomer specifications, and safety requirements for conducting snubbing operations on critical sour wells. **Note:** Industry Recommended Practice 15 – *Snubbing Operations* was under review at the time of this publication. More detailed information may be contained in that document.

The Coiled Tubing Operations section outlines the well integrity requirements during the completion and servicing of critical sour wells, particularly the inspection and pressure test requirements and material specifications of the pressure control equipment.

A Quality Control program must be implemented to ensure that the pressure control equipment utilized during completing and servicing operations is suitable for the intended service, and addresses non-API equipment as well as API equipment.

The Elastomer Guideline Selection IRP is intended to assist well operators in selecting elastomers used for well pressure seals, and addresses service and environmental conditions on seal material. Plastic and metal-to-metal seals are not included in this IRP section.

The Safety section details minimum standards and practices for completing and servicing operations with the wellhead installed or wellhead removed.

The Suspension Practices section outlines suspension methods for both newly drilled wells and completed wells to preserve the integrity of the wellbore and to maintain downhole equipment, tubular goods, and wellhead equipment to permit safe re-entry of a suspended critical sour well.

The Wellsite Personnel Training section provides guidelines with regard to training and experience levels for personnel working on completing/servicing critical sour wells to carry out each level of operation in a safe, competent manner.
2.0.5 SYMBOLS AND ABBREVIATIONS

AEUB  Alberta Energy and Utilities Board
ANSI  American National Standards Institute
ASME  American Society of Mechanical Engineers
API   American Petroleum Institute
ASTM  American Society of Testing Materials
BOP   Blowout Preventer
BPV   Back Pressure Valve
CSA   Canadian Standards Association
ESD   Emergency Shut Down (valve)
FSO   Flanged Side Outlet
IRP   Industry Recommended Practice
LPI   Liquid Penetrant Inspection
MWPR  Maximum Working Pressure Rating
NACE  National Association of Corrosion Engineers
NLGI  National Lubricating Grease Institute
OEM   Original Equipment Manufacturer
OH&S  Occupational Health & Safety
PSL   Production Specification Level
SAE   Society Automobile Engineers
SCSSV Surface Controlled Subsurface Safety Valve
<table>
<thead>
<tr>
<th>Acronym</th>
<th>Description</th>
</tr>
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<tbody>
<tr>
<td>SITRP</td>
<td>Shut-In Tubing Read Pressure</td>
</tr>
<tr>
<td>SSO</td>
<td>Studded Side Outlet</td>
</tr>
<tr>
<td>SSV</td>
<td>Surface Safety Valve</td>
</tr>
<tr>
<td>SUS</td>
<td>Saybolt Universal Seconds</td>
</tr>
<tr>
<td>VRP</td>
<td>Valve Removal Plug</td>
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2.1 **WELLHEADS**

2.1.1 **Scope**

2.1.1.1

Wellhead IRPs have been developed by the Blowout Prevention Well Servicing Committee (BPWSC) with consideration for critical sour well completion and production activities, and revised by the IRP Volume 2 Review Committee under the auspices of the Drilling and Completion Committee (DACC).

The Wellhead IRPs cover recommended practices based on engineering judgement, accepted good practice and experience for the installation, operation and maintenance of wellheads and wellhead related equipment during initial completion, re-completion, work over or subsequent production operations on critical sour oil or gas wells.

The topics related to wellheads addressed by this committee include:

- Wellhead Configuration and Design
- Wellhead Safety Shutdown Systems
- Quality Assurance and Quality Control
- Moving a Service Rig On/Off Critical Sour Wells
- Wellhead/Christmas Tree Removal
- Wellhead Protection
- Inspection Frequency of Wellheads
- Service Equipment for Critical Sour Wells
- Wellhead Freezing
- Frac Heads and Tree Savers
- Wellhead Records Keeping
2.1.1.2
Throughout this IRP the API term SSV (surface safety valve) is used rather than the term ESD (emergency shut down) valve widely used in the field.

2.1.1.3
Throughout this IRP, frequent reference is made to API Specification 6A for Wellhead and Christmas Tree Equipment\(^1\), and the sour service material requirements of NACE MR0175, latest edition\(^2\) at the time of composing this IRP, the Nineteenth Edition of API Specification 6A was the latest edition. These documents are anticipated to be further supplemented, revised and amended, and reference should be made to the most current edition and any appropriate supplements or revisions issued in the future.

2.1.2 WELLHEAD CONFIGURATION AND DESIGN OF COMPONENTS

2.1.2.1 General Requirements

IRP All wellhead and Christmas tree components shall be manufactured in compliance with API Specification 6A, latest edition (currently Nineteenth Edition)\(^1\) and all current supplements, and shall bear the API monogram.

IRP In addition to the minimum specifications outlined in the API document, the tubing head spool (above secondary seal), tubing hanger and Christmas tree assembly working pressure ratings (as defined by API 6A) shall be equal to or greater than the bottomhole pressure of the producing formation.

IRP Should the produced fluid pressure exceed the working pressure rating of the wellhead, the operator shall replace the wellhead with appropriate equipment.

NOTE: Refer to Appendix A, Figures 1 and 2 for wellhead and Christmas tree description and nomenclature.
Material selection requirements, specifications and guidelines for metallic wellhead and Christmas tree components are attached as Appendix E of this IRP.

IRP 2.11 contains recommended material selection requirements, specifications and guidelines for nonmetallic (elastomer) wellhead and Christmas tree components.

2.1.2.2 Pressure Test Requirements

IRP The operator shall ensure that the wellhead and Christmas tree assembly have been hydrostatically tested to the appropriate test pressure as per API 6A prior to shipment. Upon installation, the primary and secondary seals are to be activated and pressure tested to the lesser of the working pressure rating of the adjacent wellhead flange or 80% of the collapse resistance of the casing.

IRP After installation of the wellhead, all field connections above the secondary seal shall be pressure tested to the API maximum working pressure rating (MWPR). It is recommended that the upper Christmas tree assembly, including master valves, wellhead cross or tee, cap assembly, wing and surface safety valve (SSV), be tested to their API maximum working pressure rating (MWPR). The annulus between the production casing and tubing should be tested to the lesser of the equipment maximum working pressure rating or 1.1 times the SITHP.

NOTE: A method of calculating shut in tubing head pressure (SITHP) from the bottomhole pressure of the producing formation is outlined in Appendix F.

2.1.2.3 Wellhead Configuration - Flowing Wells

This IRP on the wellhead configuration of flowing critical sour wells includes recommendations for single, dual and hot oil circulating wellheads.

All major exterior component connections should be flanged or studded.

IRP A block cross or tee (see Appendix A, Figure 5), in conjunction with a bottomhole test adapter (cap assembly) is recommended
over a combination flow tee and test adapter for the top fitting on the wellhead.

**NOTE:** The block cross offers an alternative access to the wellbore along with providing a very solid and sturdy configuration.

All studded side outlets (SSOs) or flanged side outlets (FSOs) that access a casing annulus should have valve removal (VR) thread preparations (see Appendix A, Figure 6) including the hot oil circulation inlet/outlet.

The tubing hanger back pressure valve preparation, tubing head adapter flange, master valves, block tee or cross and top adapter should be sized so as not to restrict the passage of downhole tools or the running of the back pressure valve.

The tubing head flange should be sized to assure that full access to the production casing is possible. Production casing is defined as the casing which is packed off in the secondary seal of the tubing head.

**IRP** All end connections on the wellhead shall have pressure relief access, such as tapped bullplugs with needle valves. The exception to this clause will be the blind flange opposite to the wing valve on the flow cross.

All working valves should have a backup valve in place (see Appendix A, Figure 3) for a typical wellhead assembly. Master valves are working valves and therefore two are required. The two master valves can be in the form of a composite or block valve for single and dual completions.

Consideration should be given to the need to perform high pressure stimulation. In this regard, the installation of a lower master valve of a higher working pressure rating than the upper master valve and the other Christmas tree components may be advantageous.

When an annulus is isolated by a down hole packoff (e.g. packer) and is liquid filled or is isolated downhole by cement (as in intermediate casing strings) the annulus valve is not considered a working valve. Therefore, one valve per annulus is sufficient. However, in the case of a hot oil
circulating well where the annulus valve is used on the return line, a second annulus valve should be installed on the opposite casing outlet.

**IRP**  The injection line on a hot oil circulating string shall be equipped with a check valve and the return line shall have an automatic shut-off valve.

**IRP**  All critical sour wells on production and capable of flowing to atmosphere must be equipped with a surface safety valve (SSV). The SSV API maximum working pressure rating must be equal to or greater than the bottomhole pressure of the producing formation. Immediately downstream of the wing valve is the generally preferred location of the SSV. The wing valve is the backup for the SSV and is the working valve; therefore, the SSV is only utilized for which it was intended (i.e. as an emergency shut down valve) see Appendix A, Figure 3.

Hi/lo pressure pilots should be downstream of the wellhead SSV. Multi pilots (sensing other parameters) can be utilized to activate the wellhead SSV. Placement of these pilots is dependent upon the operator’s surface facilities.

**NOTE:**  A crown or swab valve is optional and can be installed at the operator's discretion -- see Appendix A, Figure 3.
2.1.2.4 Wellhead Configuration - Pumping Wells

(Also refer to IRP Volume 5 - Minimum Wellhead Requirements)

Pumping wellheads for critical sour wells require definite component changes over standard pumping wells (see Appendix A, Figure 4). The following are considerations:

A pumping well that has the potential to flow to atmosphere at sustained rates of at least 8 m$^3$ per day of liquids and has a hydrogen sulphide content of 10 moles per kilomole or greater in the gas phase shall be equipped with a full opening master valve, a hydraulic rod blowout preventer and an environmental blowout preventer.

All major exterior component connections from the tubing head spool should be flanged or studded up to the male thread on the stuffing box.

**IRP**  All critical sour wells on production and capable of flow to atmosphere including pumping wells must be provided with a surface safety valve (SSV). Fittings upstream of the SSV shall be flanged or studded. The pressure switch or pilot to activate the SSV and to shut down the pump jack should be located between the pumping tee or cross and the SSV.

**IRP**  A flanged master valve in conjunction with the rod BOP for use in workovers or polished rod failures shall be utilized.

The stuffing box should be of the dual pack variety.

**IRP**  An environmental shut in device shall be installed in the vertical run of a pumping wellhead, such as the illustrated environmental BOP (Appendix A, Figure 4), to prevent an H$_2$S release to atmosphere in the event of a polished rod break.

**NOTE:** The environmental BOP has two primary functions:

1. to provide a seal across the bore in the event of a polished rod failure, for example by a spring loaded flapper (refer to Appendix A, Figure 4).
2. to detect stuffing box leaks. An environmental BOP normally has two pressure-sensing ports. One port can be equipped with a pressure switch to shut down the pump jack. The ports are located beneath a packing element which seal around the polished rod. Any stuffing box leak thus causes a pressure increase in the area between the stuffing box and this packing element. The 2nd port can be tied into other safety systems or blanked off (refer to Appendix A, Figure 4).

2.1.2.5 Design of Components – Flowing Wells

This IRP on the design of wellhead components for flowing critical sour wells comprises notes on components for singles, dual and hot oil circulating wellheads as follows:

- Extended neck tubing hangers complete with a back pressure valve (BPV) preparation should be utilized. The extended neck confines and restricts the produced sour fluids from the top bowl's lock down screw assemblies and ring gasket of the tubing head. Other styles of tubing suspension systems which give the operator the BPV preparation and provide similar protection to the lock down screws, etc. are acceptable.

- Control lines for sub surface safety valves should exit through the tubing hanger and tubing head adapter flange. (see Appendix A, Figure 8). A similar exit configuration shall apply to other capillary tube and/or electrical cable outlets from downhole pressure/temperature sensors etc.

**NOTE:** Type 'RX' pressure energized ring gaskets are the type of gasket for 6B flanges (14/21/69 MPa working pressure) used in this application.

The configuration of the 'RX' with the matching 23° angle of the ring groove has proven to be a better sealing type of ring gasket. All working ring gaskets, used in the drilling and completion operations (e.g. between BOPs and wellhead components), may be 'R' type but should be replaced with the 'RX' style on final assembly see Appendix A, Figure 9.

- When the use of sulphur solvents such as dimethyldisulphide (DMDS) are contemplated, special considerations should be given to the selection of DMDS resistant elastomers or the use of metal to metal seals to ensure long term sealing integrity.
2.1.3 WELLHEAD SAFETY SHUT-DOWN SYSTEMS

2.1.3.1 General Requirements

IRP All critical sour wells on production and capable of flowing to atmosphere must be equipped with a surface safety valve (SSV).

IRP The valve portion of the SSV shall conform to API Specification 6A\(^1\), latest edition (currently Nineteenth Edition, 2004), in all respects and shall meet or exceed the material requirements of NACE MR0175, latest edition\(^2\). Minimum requirements include temperature classification ‘L’ (-46°C or -50°F), material class DD, EE, FF, HH (sour H\(_2\)S, low CO\(_2\)) and PSL 2. If the operating temperature drops below 10°C (50°F) temperature class K-U is required.

SSV actuator requirements and specifications are covered in API 6A\(^1\). Material requirements and specifications for wellheads including SSVs are attached as Appendix E of this IRP. Elastomer guidelines are contained in IRP 2.11.

IRP The SSV shall have an API maximum working pressure rating (MWPR) equal to or greater than the bottomhole pressure of the producing formation.

The SSV should preferably be installed immediately downstream of the wing valve see Appendix A, Figure 3.

SSVs should be ‘fail-safe closed’ (i.e. control line pressure open, spring assisted close). Fusible plugs can be installed in the control line for fire protection.

The SSV may be either direct-controlled, sensing pressure change at the valve, or remote-controlled where sensing devices are remotely located at various high risk areas throughout the system. Remote controlled SSVs for critical sour wells it is recommended.

Where a SSV is installed in conjunction with a surface controlled subsurface safety valve (SCSSV), the SSV should close before the SCSSV to reduce wea of the SCSSV.
NOTE: A surface safety valve (SSV) as defined in API Specification 6A, latest edition is "an automatic wellhead valve assembly which will close upon loss of power supply". It is designed to shut in a well automatically in the event of abnormal pressure fluctuations in the flowline due to fire, ruptured line, surface equipment faults/failure, damaged wellheads, or other cause.

2.1.3.2 Production Testing – Temporary Facilities

IRP SSVs shall be installed on the wellhead during all production testing operations. The generally recommended location is immediately downstream of the wing valve.

Recommended mode of actuation is pneumatic (air to opens spring assisted close).

Supply gas should be dry and non-flammable, preferably nitrogen or air.

Control lines to SSVs should be well exposed along common paths. Recommended control line type is rubber or plastic to permit easy interruption of gas supply. Exceptions to the latter are required in areas of vehicle/heavy load traffic where steel lines are normally used.

A minimum of three remote shut-down actuators should be located along common paths on the lease site. Recommended locations include:

- the office trailer(s),
- testing unit, and
- an additional upwind location.

Remote shut-down actuators are manual and thus are activated at the discretion of individuals on the lease. The location of remote shut-downs must be clearly identified (by flags or signs for example). All individuals on the lease have the responsibility to be aware of the location of the remote shut downs.

Function testing of all remote and automatic SSV shut-in devices should be performed prior to initial start-up. Remote shut down function tests should be performed daily except where it would disrupt/interfere with
production testing requirements, in which case the test could be done during a rate change, for example. As a minimum, visual inspection of the SSV and shut-down system should be performed daily.

**IRP**

Prior to start up of testing operations, all equipment upstream of the chokes including the SSV, shall be pressure tested to at least 1.1 times the shut-in tubing head pressure. It is recommended that the SSV and other equipment upstream of the choke be tested to their rated working pressure.

2.1.3.3 Permanent Facilities

The generally preferred location of the SSV is immediately downstream of the wing valve. Except for pumping wells, sensing devices for automatic shut in should be downstream of the SSV. Mode of actuation may be pneumatics, hydraulics or electric, as dictated by individual well requirements and operator preference. Supply gas lines and fittings should be AISI 316 stainless steel or equivalent. SSV shut-in should include, but not be limited to, hi/lo line pressure. Multi-pilots (sensing other parameters) can be utilized to activate the wellhead SSV. Placement of these pilots is dependent upon the operator's surface facilities.

Permanently attached lock-open devices are not permitted on SSV actuators.

Function testing should be performed monthly. In addition, a differential pressure leak test should be performed every three months. The results of function tests and differential pressure tests should be recorded. Function testing and leak testing is not required for shut in or suspended wells.


With reference to API Specification 6A, latest edition\(^1\) "The SSV actuator manufacturer shall make available, as an accessory, a heat sensitive lock-open device ... ...the heat sensitive lock-open device shall maintain the SSV valve in the open position at atmospheric temperatures up to 150°F... the lock-open device shall allow the SSV to automatically close within six minutes after being subjected to, and maintained in a controlled environmental temperature of 1000°F."
When temporary lock-open devices need to be used on critical sour wells (i.e. during well maintenance), consideration should be given to the use of heat sensitive lock-open devices.

2.1.4 QUALITY ASSURANCE AND QUALITY CONTROL LEVELS

IRP  The four primary components (i.e. tubing head, tubing head adapter, lower master valve and tubing hanger) of critical sour wellheads must meet API Specification 6A, latest edition

IRP  These four components, as a minimum, must comply to Product Specification Level three (PSL III) as defined by API 6A.

IRP  Secondary components must, as a minimum, comply to Product Specification Level two (PSL II) requirements.

IRP  All wellhead components for critical sour wells must, as a minimum, comply to Temperature Classification L (-46°C or -50°F) and material class DD, EE, FF, HH (sour service) as defined by API 6A. If the operating temperatures drop below 10°C (50°F), temperature class K-U shall be required.

IRP  Materials for all wellhead components for critical sour wells will conform to NACE Standard MR0175, latest edition (also refer to Appendix E of this IRP and IRP 2.11 for typically used materials).

**NOTE:** A primary wellhead component is a piece of equipment which, if it failed, would result in an uncontrolled leak of wellbore fluid/gases to the atmosphere (i.e. a master valve).

A wellhead component may be classified as a secondary piece of equipment if a primary component can be activated to stop the uncontrolled leak of wellbore fluids/gases to the atmosphere (i.e. a wellhead flow cross/tee).

Primary and secondary components are defined and specified in API 6A, Nineteenth Edition (2004).
For additional guidance on selecting recommended Product Specification Levels (PSLs), refer to API 6A, Nineteenth Edition (2004).

2.1.5 **Suspended Critical Sour Wells**

**NOTE:** The wellhead requirements for suspended critical sour wells are contained in IRP 2.13 “Suspension Practices for Critical Sour Wells”.

2.1.6 **Moving a Service Rig On/Off Critical Sour Wells**

2.1.6.1 **Intent**

This IRP covers requirements for preparing a well when moving a service rig on or off a critical sour well. The intent is that, should the wellhead be damaged in the rig move, the well would still be under control via plugs and load fluid.

2.1.6.2 **Recommended Practices**

The following recommendations apply to perforated critical sour wells capable of production, (a) prior to moving a service rig on the well, or (b) rigging down and moving a service rig off the well:

- Shut-in the well, isolate and depressurize the flowline.
- If the well is not on rod pump, install a downhole wireline plug in the tubing and pressure test. If it is not possible to install a downhole wireline plug, load the well with an appropriate density kill fluid.∗ Install a backpressure valve (BPV) in the tubing hanger. The tubing plug and BPV is to stay in place until (a) the rig is over the well and fully rigged up, or (b) until rigged down and the rig is fully off the well.
- Alternatively, for wells equipped with surface controlled subsurface safety valves (SCSSVs), the well can be shut-in on the SCSSV. Leak test the SCSSV according to IRP 2.3 before moving on/off the service rig. The SCSSV is to remain closed throughout the rig move.
- If the wellhead/Christmas tree will be removed and the BOPs installed as soon as the service rig has moved

∗ It is recommended that the hydrostatic head pressure be at least 1400 kPa above reservoir pressure.
• over the well and rigged up, it may be more efficient to prepare the well as per the following section 2.1.7 “Wellhead/Christmas Tree Removal” prior to moving on the service rig.

• For critical sour wells on rod pump, the well should be loaded with an appropriate density kill fluid* prior to moving the rig.

2.1.7 Wellhead/Christmas Tree Removal

2.1.7.1 Intent

The overall intent is that the producing formation remains isolated at all times while the BOPs and/or wellhead/Christmas tree are removed.

2.1.7.2 Recommended Practices

Before the wellhead/Christmas tree is removed, at least two barriers should be put into place. The following information outlines the types of barriers to be considered.

• The well could be killed or loaded with an appropriate density kill fluid.*

• A back pressure valve (BPV), could be installed in the tubing hanger.

• A wireline plug could be set. A wireline plug set in a landing nipple is preferred but where this is not possible a hookwall type tubing plug is acceptable. The wireline tubing plug shall be set deep in the well so that the hydrostatic pressure above balances or overbalances the reservoir pressure below. The wireline tubing plug shall be tested to at least 7000 kPa differential.

For wells on rod pump and which can flow to atmosphere, circulate the well to a kill fluid prior to pulling the sucker rod. If not possible to circulate the wells load up the tubing with kill fluid and top up annulus. The installation of a rod BOP is required while pulling the sucker rods. With the rods out, a back pressure valve shall be installed in the tubing hanger and a downhole wireline tubing plug be installed prior to removing the wellhead/Christmas tree components and installing the BOPs or removing the BOP to install the wellhead.

* It is recommended that the hydrostatic head pressure be at least 1400 kPa above reservoir pressure.
Completing and Servicing Critical Sour Wells

IRP During the foregoing operations a stabbing valve assembly with a working pressure rating greater than the shut in wellhead pressure, rated for sour service and equipped with the correct tubing threads must be available. The stabbing valve assembly including tubing threads should be carefully inspected and checked for functionality prior to removing the wellhead/Christmas tree or BOPs.

IRP With the tubing out of the hole and if the perforations are not isolated (with a plug set in a packer for instance), a bridge plug or equivalent will be set downhole prior to removal of the BOPs. It is recommended that the bridge plug or equivalent be set deep in the well such that hydrostatic pressure above balances or overbalances the reservoir pressure below. The bridge plug or equivalent shall be tested to at least 7000 kPa differential.

2.1.8 WELLHEAD PROTECTION

2.1.8.1 Premise
A substantial portion of well blowouts are caused by reasons other than equipment failure or incorrect procedures. The predominant cause of this group of 'other' failures is vehicular damage. Potential sources of vehicular damage include operator vehicles, service vehicles, maintenance tractors, graders, seismic equipment, tank trucks and unauthorized visitors.

2.1.8.2 Recommended Practices
IRP All wellheads must be clearly marked and visible in all seasons.

Acceptable means of marking would include painting in a color that stands out from the background and flagging of wells not clearly visible due to snow or brush cover.

Physical barriers that are clearly visible should be constructed around wellheads of critical sour wells to prevent accidental vehicle damage. These barriers should be readily removable to accommodate servicing operations.

Access roads to wellsites should contain gates restricting entry. These gates may be opened during servicing operations as a safety precaution,
or in emergency situations (e.g., forest fires). A clearly visible cautionary sign should be located on the gate restricting access. The sign should include "Critical Sour Well", well name including location (LSD), and 24-hour emergency phone number consistent with the Emergency Response Plan (licensee or operator as appropriate).

Farming operations should not be permitted within a 25 m radius of the wellhead.

**NOTE:** An example of an acceptable barrier would be a fence constructed from steel tubing anchored in larger diameter tubing sleeves cemented in the ground at the wellhead corners, or cement dividers encircling the wellhead.

The sensitivity of the well must be considered when addressing whether or not additional wellhead protection is required. Factors affecting well sensitivity are:

- population density in the vicinity of the well,
- the presence of public facilities or transportation corridors in the vicinity of the well, and
- the completion status of the well (i.e., producing, suspended or not yet completed).

Additional wellhead protection measures which may be considered are designing lease roads so that normal traffic does not pass near the wellhead, constructing berms or ditches separating the lease roadway from the wellhead, and complete fencing around the perimeter of the lease.

### 2.1.9 Inspection Frequency of Wellheads

#### 2.1.9.1 Suspended Wells

**NOTE:** Inspection frequency and inspection requirements for suspended critical sour wells are covered by IRP 2.13 "Suspension Practices for Critical Sour Wells".
2.1.9.2 Producing Wells

**IRP** Producing critical sour wells must be inspected and serviced at least once every year. A good routine plan for this inspection would be late fall before freeze-up.

Inspection and servicing of the wellhead and Christmas tree should include:

- Visual inspection of all equipment to check for any loose or damaged parts.

- Lubrication of all valves (body and stem bearings) to prevent corrosion and excessive wear of valve parts. Venting and draining instructions may be needed depending on manufacturer's valve. Generally any good grade SAE #1 grease is recommended for body lubrication and for bearings—see Appendix B. The grease selected is most effective if it is not soluble in the well effluent. The valve manufacturer should be consulted in selecting an appropriate grease. Lubrication pressure must never exceed the maximum working pressure of a valve.

- Checking stem packing on valves for leakage and adjusting or repacking as needed.

- Cycling surface safety valves (SSVs) to make sure they are operational.* The high and low pilots should be checked to ensure they operate at set point limits. All tubing control line connections should be checked for possible leaks and repaired as needed.

- Manual operation of all wellhead valves to ensure they work and hold pressures.

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* As standard practice, SSV’s should be function tested at least once per month and leak tested every 3 months. Refer to “Wellhead Safety Shutdown Systems” IRP (section 2.1.3) for more details.
• Recording and reporting all annulus pressures.

2.1.10 SERVICE EQUIPMENT FOR CRITICAL SOUR WELLS

2.1.10.1 Back Pressure Valve

NOTE: A back pressure valve (BPV) is a device which seats in a tubing hanger or coupling to seal the wellbore while the blowout preventers are removed and the Christmas tree is installed/removed. It is also used to temporarily isolate the Christmas tree from well pressure, for repairs, without killing the well (see Appendix C, Figure 1).

Back pressure valves are installed in four different ways. The method used depends on when the BPV is installed:

• By hand on the rig floor before the tubing hanger is run.
• Using sucker rods after the tubing hanger is landed, but before the well is flowing.
• With a lubricator when the well is flowing.
• By wireline when long distance makes it impractical to use the above methods; for instance, when using "Otis" recess/locking dogs type BPV rather than the "Cameron" threaded type.

2.1.10.2 Back Pressure Valve Lubricator

NOTE: The back pressure valve lubricator is a tool for setting and recovering back pressure valves under pressure. The lubricator is used whenever there is pressure in the wellbore (see Appendix C, Figure 2).

2.1.10.3 Valve Removal Lubricators and Plugs

NOTE: The valve removal (VR) lubricator is used to install or remove a valve removal plug (VRP) in a head or spool side outlet so that an annulus gate valve can be installed, removed or repaired while under pressure. The VR lubricator mounts on the valve outlet flange and installs and removes the VRP through the open valve bore, even though the valve is under pressure. Studded, clamped and flanged side outlets of all heads are normally threaded to accept VR plugs (see Appendix C, Figure 3).
2.1.10.4 Equipment Requirements (includes Back Pressure Valves, Lubricators & Valve Removal Plugs)

IRP Lubricators must have a working pressure rating equal to or greater than 1.3 times shut-in tubing head pressure (SITHP). Lubricators must be pressure tested after installation on the wellhead to at least SITHP.

Each qualified API 6A\(^1\) wellhead manufacturer will have their own designed and tested lubricators, BPVs and VRPs available for use with their own equipment.

IRP Equipment must be in good, safe operational condition for the intended service conditions. All equipment must be suitable for sour service and comply with NACE MR0175, latest edition\(^2\). Specific material and elastomer requirements, specifications and guidelines have been provided in Appendix E of this IRP and IRP 2.11.

2.1.10.5 Procedures

IRP Each manufacturer must have an approved operating manual which includes running and retrieving procedures for BPVs and VRPs. All personnel conducting these operations must be fully trained and experienced in these procedures.

2.1.10.6 Inspection

IRP All BPVs, lubricators and VRPs must be visually inspected prior to usage to ensure everything is in good safe operational condition. Should any equipment be defective, it must be properly repaired before usage. The, lubricator must be pressure tested to full rated working pressure prior to each job. Liquid Penetrant Inspection (LPI) should be done at least once a year to check for cracks. Each manufacturer must serialize his lubricator as well as document service history of the part.
2.1.11 WELLHEAD FREEZING

2.1.11.1 General

Freezing a plug in tubing or casing of a critical sour well may be necessary from time to time when other pressure control methods are not possible. The use of freezing as a well servicing technique should be kept to the absolute minimum. It is by its nature a risky procedure and the qualifications of personnel and all procedures should be carefully reviewed between the freeze specialist and the well operator/owner ahead of time.

The procedure consists of placing a gelled fluid at the freeze point in the tubing or casing. Dry ice is packed around the freeze point to freeze the gel into a solid plug. After freezing the plug in place, it is pressure tested from above. It is recommended to pressure test to twice the shut-in wellhead pressure.

After pressure testing, the equipment above the plug can be removed and new equipment installed and/or repairs carried out. Because of the risky nature of the freezing procedure it is recommended that the defective part be replaced with a new one rather than attempt to repair it on the lease.

2.1.11.2 Qualifications of Personnel

Personnel working on freezing critical sour wells should have considerable experience in freezing procedures. Refer to Section 2.14.

2.1.11.3 Equipment Requirements

All equipment which may be exposed to sour well fluids shall be in accordance with the material requirements of NACE Standard MR0175, latest edition²

There should be a pressure gauge positioned between the injection point and the working valve to monitor injection pressures and build-up rates due to channeling.

Injection equipment should be capable of providing pressures equal to the working pressure of the wellhead equipment or twice the maximum shut-in pressure, whichever is lower.
2.1.11.4 General Procedure

1. Hold a safety meeting with all people involved. Carefully review procedures and ensure all equipment required for repairs is available on lease.

2. Establish an injection point. Where one does not exist it may be necessary to hot-tap.

3. Build an ice crib and pack dry ice around freeze point. The crib should be a minimum of 60 cm (24") deep. The crib should be built below the injection point or in such a manner that the injection point will not freeze. The crib should also be positioned a sufficient distance from the faulty piece of equipment so that the point at which repairs are to be done will not freeze.

4. Wait one hour for the metal to chill.

5. Pressure up lubricator/mud injector and squeeze freeze gel into freeze point. Inject sufficient gel to ensure uncontaminated gel is in the area to be frozen.

6. Wait a minimum of one hour to one and one-half hours per inch of freeze diameter (i.e. if freezing 178 mm casing, wait 7 to 10.5 hours). If necessary protect the ice crib from rain or snow with a tarp and from sun with insulation.

7. Pressure test freeze plug to twice the shut-in wellhead pressure or the maximum working pressure rating of the wellhead equipment, whichever is lower. Maintain this pressure test for a period of time equal to or greater than the time required to complete the wellhead repairs. After pressure testing, open working valves and allow plug to sit for at least 15 minutes with valves open to further test the plugs.

8. Carry out repairs on wellhead. Pressure test new equipment against freeze plug. Leave pressure trapped above the freeze plug, so that it does not jump up the hole once thawing starts.

9. Slowly thaw out plug and flow out the freeze gel. If time and weather (plus 0°C) permit, plug can be thawed naturally. If speed is required or cold weather is present, then steaming will be required to thaw plug. Use extreme caution. Cover the wellhead with a tarp and allow steam to flow gently onto the wellhead until the frost on the outside disappears (minimum of one hour). When the outer metal is warm to touch then full force steam can be applied. Allow approximately the same amount of time for full force steaming as was
used for freezing. This will permit the plug to thaw completely before attempting to flow it back.

2.1.11.5 General Precautions

• Keep work area uncluttered.

• Unnecessary personnel should stay clear of the work area during repairs.

• Monitoring of H₂S is required, and the type of monitoring is dependent on the complexity of the job. In the case of H₂S work, breathing apparatus should be worn during repairs, and it is recommended that safety personnel and equipment be present.

• Never strike or jar the frozen equipment with a hammer.

• Ensure area where freeze plug is to be set is free of hydrocarbons. The plug is a water based gel and the two do not mix very well; hydrocarbon will prevent the plug from setting properly. The hydrocarbons can be removed by flushing the section to be frozen.

• When freezing multiple casings and tubings, freeze from outside inward. Test each annulus one at a time.

2.1.12 Frac Heads and Tree Savers

2.1.12.1 General Requirements

Frac heads or tree savers are to be used whenever pumping or stimulation pressures could exceed the API maximum working pressure rating for the wellhead/Christmas tree.

Acid jobs performed through the original wellhead/Christmas tree without the use of a frac head or tree saver would be acceptable provided the treatment pressure did not exceed 90% of the wellhead/Christmas tree API maximum working pressure rating. After completion of the jobs it is recommended that all wellhead/Christmas tree valves exposed to the acid be opened, closed and re-greased.
2.1.12.2 Frac Heads

**IRP** Frac heads for critical sour wells are to meet API Specification 6A, Nineteenth Edition (2004)\(^1\) and NACE Standard MR0175, latest edition\(^2\) The lower master valve, adapter flange and other primary components for frac heads shall, as a minimum, comply to Product Specification Level Three (PSL III) as defined by API 6A. All other frac head components should conform to PSL 1 (see Appendix F, Figure I).

Upon installation, the frac head should be pressure tested to its API maximum rated working pressure and the operating pressure should not exceed 90% of the API rated working pressure.

All frac heads should have full bore access to tubing.

**NOTE:** For guidance on material requirements and specifications including elastomers refer to Appendix E of this IRP and IRP 2.11.

2.1.12.3 Maintenance of Frac Heads

Prior to service or after each job, all valves should be pressure tested and charted. The valves should also be greased.

All bolts should be torqued to API 6A, Nineteenth Edition (2004)\(^1\) specifications.

**IRP** Prior to installation on critical sour wells, frac heads are to be pressure tested as specified in API 6A, Nineteenth Edition (2004)\(^1\).

A log of shop servicing and pressure testing of frac heads must be kept at all times by the supplier of the frac head.

2.1.12.4 Hook Up (Frac Heads)

**IRP** Use hammer unions consistent with frac iron pressure ratings. All connections between the top of the frac head tee and the first hammer union must be flanged or clamped. Threaded connections will not be used for critical sour wells.
2.1.12.5 Tree Savers

Tree saver components are to be suitable for sour service as per NACE Standard MR0175, latest edition and all internal parts to be new when working on critical sour wells.

All seals should be replaced after any H₂S service.

IRP Plug valves are to be inspected, greased and pressure tested after every job.

IRP A log of all parts, their material and date of servicing is required.

IRP The tree saver is to be shop pressure tested to a minimum of 1.5 times the rated working pressure before every job.

IRP Do not exceed 90% of the rated working pressure of the tree saver during well work.

IRP The bleed off line must be secured.

NOTE: For further guidance on material requirements and specifications including elastomers for tree savers refer to Appendix E of this IRP and IRP 2.11 (Guidelines For Selecting Elastomeric Seals)

2.1.12.6 Hook-Up (Tree Savers)

IRP Use hammer unions consistent with frac iron pressure ratings. Connections between the tree saver and the frac iron shall be flanged or clamped. Threaded connections should not be used for critical sour wells.

2.1.13 WELLHEAD RECORDERS

2.1.13.1 Requirement

IRP A list of wellhead components must be maintained by the owner/operator for critical sour wells to ensure the safe and orderly conduct of workover operations in both normal and emergency situations.
This list should be sufficiently detailed so that all components of the wellhead can be identified, and both the proper equipment (the proper specifications) and the correct workover procedures may be incorporated in the workover plan.

2.1.13.2 Recommendations

Wellhead records should contain:

- The make and model of all wellhead components, as well as all pertinent specifications such as sizes and working pressures. The thread connections in the bottomhole test adapter (wellhead cap assembly) and tubing hanger (including BPV threads) should be noted.

- A schematic of the wellhead identifying components and their configuration.

- Date of initial installation and date of subsequent workovers (with details of any wellhead changes).

Wellhead records should be checked for accuracy as part of the semi annual or annual wellhead inspection. The records should be updated each time the well is serviced or worked on.

Wellhead records should be updated and maintained at the office of the licensees responsible for coordinating the emergency response plan for the field containing that well.
APPENDIX A. WELLHEAD CONFIGURATION

Figure 1. Typical Wellhead Assembly Nomenclature
Figure 2. Typical Christmas Tree Assembly Nomenclature

* Reproduced from API6A 15 Edition with permission
Figure 3. Typical Wellhead and Tree for Critical Sour Service
Figure 3a. Wellhead Configurations
Figure 4. Typical Critical Sour Pumping Christmas Tree Configuration
Figure 5. Typical Studded Cross or Tree Assembly
Figure 6. Typical Tubing Head Spool C/W Valve Removal Threads
Figure 7. Tubing Hanger Suspension System C/W Back Pressure Valve Preparation
Figure 8. Typical Control Line Exit Through The Wellhead Assembly
Figure 9. Typical RX Ring Gasket Configuration
APPENDIX B. WELLHEAD GREASE SPECIFICATIONS

Typical Properties & Technical Data

The grease used for wellhead service should contain special ingredients that combat the corrosive action of the H$_2$S and moisture found in natural gas.

<table>
<thead>
<tr>
<th>Typical Properties</th>
<th>Valve Grease No. 1</th>
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</thead>
<tbody>
<tr>
<td>NLGI (National Lubricating Grease Institute)</td>
<td>1</td>
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<td>Worked Penetration @ 25°C</td>
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**Oil Viscosity**

<table>
<thead>
<tr>
<th>Viscosity</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>cSt @ 40°C</td>
<td>58.4</td>
</tr>
<tr>
<td>SUS$^1$ @ 100°F</td>
<td>305</td>
</tr>
<tr>
<td>Dropping Point$^2$, °C</td>
<td>93</td>
</tr>
</tbody>
</table>

$^1$ SUS - Saybolt Universal Seconds.

$^2$ Temperature at which grease changes from semi-solid to a liquid state (ASTM D566-64).
APPENDIX C. SERVICE EQUIPMENT

Figure 1. Back Pressure Valve (Threaded Type)
Figure 2. Typical Hydraulic Lubricator
Figure 3. Typical Hydraulic Lubricator (Valve Removal Plug)
APPENDIX D.

Figure 1. Frac Head
Figure 2. Tree Saver

1. Plug Valve
2. Hammer Union
3. Hammer Union
4. Flow Tee
5. Wellhead Valves
6. Spool with Tubing Hanger
7. Double Style Pack Off Nipples
8. Casing Head
9. Casing
10. Mandrel
11. Plug Valves
12. Tubing
APPENDIX E.

Material Requirements And Specifications For Wellheads And Wellhead Servicing Equipment For Critical Sour Wells - General Notes

1. To ensure displacement of trapped acids and gases, valve stem packing and valve cavities should be greased prior to and subsequent to acid stimulation operations or injection of similar corrosive materials.

2. Temperature range L is selected for \(-46^\circ C (-50^\circ F)\) minimum temperature rated equipment. It should be noted that the upper temperature limit \(82^\circ C (180^\circ F)\) is based on an upper temperature limitation for typically used elastomers. Where operating temperatures drop below \(-46^\circ C (-50^\circ F)\), Temp class K-U should be utilized.

3. RX ring joint gaskets are preferred, oval gaskets are sensitive to bolt torque and are more subject to deformation (more difficult to achieve seal on re torque). New RX ring gaskets are to be installed as per OEM requirement.

4. There is no specific design standard for pressure containment principles or manufacturing processes. It is recommended, where applicable, that the materials and quality control principles of API 6A be applied for these components.

5. API 6A refers to the latest edition\(^1\).

6. Note that elastomers can be degraded as a result of exposure to commonly used chemical such as amines, sulphur dispersants or stimulation fluids. Consult IRP 2.11, Guidelines for Selecting Elastomeric Seals.

7. The minimum standard and the material examples are cited to prevent only sulphide stress cracking due to \(H_2S\) exposure. Other forms of corrosion such as pitting or galvanic corrosion must also be considered in addition to sulphide stress cracking and are not covered by these recommendations. Consideration
of all forms of corrosion may dictate the use of a corrosion resistant alloys, coatings or chemical corrosion inhibitors.
## APPENDIX F. SUMMARY - WELLHEAD AND SERVICING MATERIALS

Material Requirements And Specifications For Wellheads And Wellhead Servicing Equipment For Critical Sour Wells

<table>
<thead>
<tr>
<th>Component</th>
<th>Minimum Recommended Standard</th>
<th>Typically Used Materials</th>
<th>Comments</th>
</tr>
</thead>
</table>
| 1. Within Scope of API 6A  
A. Primary  
  ▪ Tubing Spool  
  ▪ Wellhead Tubing Hanger  
  ▪ Wellhead Adaptor  
  ▪ Lower Master Valve  
| API 6A  
  PSL III  
  Temperature Range L  
  Material class DD, EE, FF, HH  
  NACE MR0175 latest edition | Low alloy (4130 – 4140) controlled hardness  
  Stems: K-Monel 500, Inconel 718, 17-4 PHSS  
  Gates  
  Seats: hardfaced (stellite), 410SS, 4130 | Valve stem materials may warrant additional consideration  
  See general notes (1) and (2) |
| B. Secondary  
  ▪ Wing Valve  
  ▪ Upper Master Valve  
  ▪ Swab (Crown) Valve  
  ▪ Top Connection  
  ▪ Flow Cross  
| API 6A  
  PSL II  
  Temperature Range L  
  Material class DD, EE, FF, HH  
  NACE MR0175 latest edition | Low alloy (4130 – 4140) controlled hardness  
  Stems: K-Monel 500, Inconel 718, 17-4 PHSS  
  Gates  
  Seats: hardfaced (stellite), 4130, 410SS | See general notes (1) and (2) |
| C. General  
  ▪ Bolting  
| API 6A  
  NACE Class II | Studs: ASTM A 320 L7M  
  Nuts: ASTM A 194-2HM | Users should be aware that flange size restrictions apply when using reduced yield strength bolting (i.e. A320 L7M)  
  - see Table 49, API 6A. |
To avoid derating, A453 Grade 660 or CRA bolting must be used.

<table>
<thead>
<tr>
<th>D. General</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Gaskets (Ring Joint)</td>
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</table>

<table>
<thead>
<tr>
<th>API 6A</th>
<th>Type 316 or type 304 stainless, fully annealed-controlled hardness Type 660 Stainless (over 4&quot;)</th>
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</thead>
<tbody>
<tr>
<td></td>
<td>See general note (3)</td>
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### APPENDIX G. SUMMARY - WELLHEAD AND SERVICING MATERIALS

Material Requirements And Specifications For Wellheads And Wellhead Servicing Equipment For Critical Sour Wells

<table>
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<tr>
<th>Component</th>
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<th>Comments</th>
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<td>1. Outside Scope of API 6A</td>
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<tr>
<td>A. Primary</td>
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<td></td>
<td></td>
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<tr>
<td>- Tree Savers</td>
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<td></td>
<td></td>
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<tr>
<td>- Wellhead Isolation Tool</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td><strong>MANDREL</strong></td>
<td><strong>MANDREL</strong></td>
<td>Packoff material should be carefully selected to prevailing servicing conditions considering resistance required using IRP 2.11- Guidelines for Selecting Elastomeric Seals.</td>
</tr>
<tr>
<td></td>
<td>NACE MR0175 latest edition materials</td>
<td>4130 – 4140 Packoff - Nitrile</td>
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<td></td>
<td><strong>VALVE</strong> API 6A</td>
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<td></td>
<td>PSL III, Temp Range L</td>
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<td></td>
<td>NACE MR0175 latest edition materials</td>
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<tr>
<td>Lubricators</td>
<td>NACE MR0175 latest edition</td>
<td>Body – L-80</td>
<td>Welded connection to meet API 6A, PSL III</td>
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<tr>
<td>Valve Removal Plugs</td>
<td>NACE MR0175 latest edition</td>
<td>4130 – 4140</td>
<td></td>
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<tr>
<td>Stuffing Box</td>
<td>NACE MR0175 latest edition</td>
<td>4130 – 4140</td>
<td>Brass bushings currently do not meet NACE</td>
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January 2007
<table>
<thead>
<tr>
<th>Component</th>
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<th>Material Range</th>
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<tr>
<td>Back Pressure Valves</td>
<td>NACE MR0175 latest edition</td>
<td>4130 – 4140</td>
</tr>
<tr>
<td>Rod Type BOP</td>
<td>NACE MR0175 latest edition</td>
<td>ASTM A487 – Class 4 or 9</td>
</tr>
<tr>
<td>B. Secondary Environmental BOP (i.e. Red-M-BOP)</td>
<td>NACE MR0175 latest edition</td>
<td>ASTM A-352, Grade LCC, LCB</td>
</tr>
</tbody>
</table>
APPENDIX H.

Calculation Of Shut-In Tubing Head Pressures

The following two methods for calculation of shut-in or static tubing head pressures (SITHP) are described in an AEUB publication entitled: “Gas Well Testing, Theory and Practice”, Fourth Edition (Metric), Appendix B7.

The first method, using average temperature and pressure, is suitable for shallow dry gas wells where the compressibility factor (Z) remains relatively constant throughout the gas column. The accuracy of the SITHP calculation is dependent on the knowledge of the average compressibility factor (Z) and temperature (T) in the well bore.

The equation is given by:

\[ P_{ts} = P_{ws} \times \exp \left( \frac{-G \cdot X}{29.26 \cdot T \cdot Z} \right) \]

Where:  
- \( P_{ts} \) = Shut-in tubing head pressure (kPa)  
- \( P_{ws} \) = Static reservoir pressure (kPa)  
- \( G \) = Specific gravity of the gas (air = 1.0)  
- \( X \) = Depth (metres)  
- \( T \) = Average temperature (° Kelvin)  
- \( Z \) = Average compressibility factor

The second method, after Cullender and Smith, employs an iterative approach utilizing progressively more indicative values of Z. Assuming a linear temperature profile, the tubing is broken into lower and upper segments with a compressibility factor calculated for each segment. After calculating the pressure at the mid point and surface of the gas column, the results are smoothed using parabolic interpolation (Simpson’s rule) thereby increasing the accuracy of the results. Although more time consuming than the first method of average Z and T, the Cullender and Smith calculation provides greater accuracy in deep gas wells where there is a significant change in Z with depth.
List of References


Further Resources

AEUB, *Oil and Gas Conservation Regulations 1986*, AEUB, Calgary, AB.
2.2  SERVICE RIG BOP STACK ACCUMULATOR AND MANIFOLD

2.2.1 Scope

2.2.1.1
The Industry Recommended Practices (IRPs), originally Alberta Recommended Practices (ARP’S) developed by the Service Rig BOP Stack, Accumulator and Manifold Committee, were updated in 2003 by the IRP Volume 2 Review Committee with consideration for completion, re-completion and workover activities on critical sour wells.

The IRPs are based on engineering judgment, accepted good practices and experience.

Topics addressed include:

- Wellhead Records Keeping
- BOP Stack Configuration
- Manifolding
- Accumulator
- Tubing Safety Valve
- Heating Equipment
- Equipment Quality Assurance
- Installation and Operation

2.2.1.2
Throughout this section IRPs are highlighted in bold type and the word “shall” or “must” is used. Additional best practices are not highlighted and contain the words “should” or “recommended”.
2.2.2 BOP Configuration

2.2.2.1 BOP Requirement

IRP Shear rams will be required where "operation complexity" and "residential density" analysis indicate a high level risk factor during a completion or workover.

In many applications, the BOP requirements of applicable regulatory jurisdictions will suffice (Reference AEUB ID 90-1).4

NOTE: Appendix C contains a matrix that aids in the determination of whether Shear Blind Rams should be used. The matrix utilizes a residential density level and an operational complexity level. The residential density level and complexity level matrix are given in Appendix C.

2.2.2.2 Ram Configuration

IRP Where shear rams are required by Section 2.2.2.1, the recommended arrangement is as shown in Appendix A, Figure I. The shear ram is an accessory to a fully-equipped sour BOP stack.

Alternatively, a shear/blind ram (Appendix A, Figure 2) shall be used in place of a conventional blind ram. Should this alternative arrangement be chosen, a ram blanking tool must be available to provide a back up to the sealing capabilities of the blind ram, and must be available on location.

NOTE: In all cases, the BOP system must be sized to accommodate the completion string components or work string being used. The annular preventer is considered as the system backup.

2.2.2.3 Spools

IRP Flanged BOP working spools with two flanged side outlets are required on critical sour wells.

NOTE: BOP spools are required to couple the BOP to the tubing head adapter spool (wellhead component) and to provide access to the wellbore or tubing/casing annulus.
Use of BOP side outlets is not recommended. Additional spools may be used where BOP configurations become more complex than the minimum configurations but primary BOP connections should be kept to a minimum. All attempts should be made to limit the number of spools used.

**IRP**  All spools must conform to applicable API and NACE standards.

**NOTE:** Where sour fluids are being circulated or flowed from the well, the bleed off line shall include a remotely actuated surface safety valve. The valve is considered part of the test equipment; however, the valve should be installed as close to the well as possible, preferably on the wing valve immediately downstream of the bleed-off valve.

### 2.2.3 MANIFOLDING

#### 2.2.3.1 Manifolds

**IRP** The Service Rig pump manifold shall not be used as a well control manifold with sour fluids.

A sour service separator/flare stack system including appropriate manifolding must be used to process sour well effluent.

**NOTE:** IRP 2.5 contains recommendations as to general equipment requirements for handling fluids at critical sour well operations.

### 2.2.4 ACCUMULATOR

#### 2.2.4.1 Sizing

**IRP** Where a shear ram is used (in addition to the required BOP stack), the accumulator shall be sized to either operate the
required BOP as per applicable regulatory requirements, or shear the completion string without recharge, whichever is the greater volume.

Where the shear/blind ram replaces the blind ram in the required BOP stack, the accumulator must function the BOP as per applicable regulatory requirements, and must be sized to provide sufficient power fluid to shear the completion string without recharge.

The back-up system nitrogen supply must be capable of closing all blowout preventers including the shear/blind ram and shear pipe in use.

**NOTE:** It may be the case that shearing the completion or work string in use places greater capacity demands or pressure requirements on the accumulator than the regulatory requirements. This must be considered when sizing an accumulator on a critical sour well.

### 2.2.4.2 Fluids

**NOTE:** Hydraulic oil or a glycol/water mix are acceptable power fluids, provided proper maintenance procedures are in place and are approved by OEM. Bacteria build up in the glycol/water fluid must be treated out. Seals must also be checked regularly. Hydraulic oil must be processed to remove or accommodate water contamination.

### 2.2.4.3 Power Supply

The use of an auxiliary power supply is left to operator's discretion.

**NOTE:** Auxiliary power is not required as a minimum standard, since, by its very nature, an accumulator will function without external power, and since a backup is required for the accumulator system.

### 2.2.4.4 Hydraulic Lines

**IRP** All hydraulic BOP control lines shall be tested to the maximum operating pressure of the accumulator system for 5 minutes prior to commencing operations.
Hydraulic lines must be fire sheathed (protected) for a minimum of 7 m horizontal distance from the wellbore.

Hydraulic hose couplers within 7 m of the wellbore must be “Lock-Type” couplers or “Hammer Union” type.

2.2.4.5 Control Locations

IRP Where shear rams are employed in addition to the required BOP stack, the control shall be solely at the master panel (accumulator) to avoid accidental shear ram closure. If the shear ram replaces the blind ram, the remote panel must operate the ram.

NOTE: As per AEUB regulations, Class III BOPs must have both master and remote controls. The master control must be able to function all BOP operations. The remote location is at the driller’s position with the master controls at least 25 m from the wellbore, located at the accumulator.

2.2.4.6 System Monitors

IRP All control manifolds shall have system pressure gauges which are to be regularly checked.

An accurate pressure gauge at the driller’s position is recommended.

NOTE: System alarms are optional.

2.2.4.7 Reservoir Venting

IRP The accumulator reservoir shall be vented outside the building and the ventline must be accessible for handheld H\textsubscript{2}S monitoring (Draeger, Gastech, etc.).

NOTE: Primary hydraulic seal leaks may result in sour fluids entering the accumulator reservoir. The vent should be inspected on routine safety checks.
2.2.5 TUBING SAFETY VALVES (STABBING VALVES)

2.2.5.1 Sizing and Rating

**IRP** The stabbing valve shall be a NACE full-opening valve with the proper threads to mate to the completion string thread in use. The minimum internal diameter must be equal to or larger than the completion string in use.

The stabbing valve must have a pressure rating equal to or greater than the BOP pressure rating.

Extended bales are recommended to allow string weight to be borne by the tubing, rather than the stabbing valve.

**NOTE:** It is desirable that the valve outside diameter be such that the valve may be stripped in through the BOP and wellhead. This may not always be possible since the valve must also be manufactured of metallic materials meeting the requirements of NACE MR0175, latest edition.

2.2.5.2 Stabbing Valve Backup

**IRP** One stabbing valve is required provided that it is only used to shut off the completion string bore in case of a well flow or to secure the well. The valve is not to be used as a working valve.

**NOTE:** It is recommended that two stabbing valves be on location.

2.2.5.3 Storage and Handling

**IRP** The stabbing valve is to be stored in an area immediately accessible to the wellbore. It is to be left in the open position. The valve must be kept clean, properly maintained, ice-free and ready for use.

**NOTE:** Handles and/or counter balances which aid in installing the valve quickly are recommended.
2.2.6 Heating and Lighting Requirements

2.2.6.1 Heat Source

IRP The heat source must be suitable for the electrical area classification in which it is used.

NOTE: Required heat is addressed in EUB Directive 37 Service Rig Inspection Manual. Heating is required on all BOP systems when the body temperature during operations is below -10° C. The source of heat (electric, steam, air, etc.) is left to operator's discretion. The BOP must be ice-free.

2.2.6.2 Tarps and Prefabs

NOTE: When heat is required, it will be necessary to install wind breaks in the sub-structure area. Prefabs or properly secured tarpaulins are recommended. Wind protection is also recommended on the floor and derrickman stations during winter operations. Where prefabs are installed, there shall be at least two exits from enclosed work areas. Other windbreaks should be at operator's discretion (i.e. pump house, etc.).

2.2.6.3 Lighting

IRP Lighting must be adequate to ensure complete visibility of well control systems.

The lighting must be suitable for hazardous areas and at least be suitable for transient vapour exposure. Safety seals must be properly maintained. Emergency lights are recommended to illuminate working floor exits and building exits.

NOTE: Critical servicing operations are often conducted on a 24-hour basis. Where operations are conducted at night, lighting must be supplied to provide good visibility to:

- All doorways, stairways and walkways
- BOP area
- Working floor
Completing and Servicing Critical Sour Wells

- Mud tank area
- Test-unit, tanks and lines
- Accumulator and pump house
- Controls (must be clearly visible and marked)

Lighting should be positioned so as not to blind the operator.

IRP 2.12.7.4 refers to other aspects of adequate lighting.

2.2.7 Equipment Quality Assurance

2.2.7.1 Metallurgy
IRP Recommended equipment material specifications are provided in Appendix B.

2.2.7.3 Elastomers
IRP IRP 2.11 Guidelines for Selecting Elastomeric Seals should be used to select BOP elastomers.

2.2.7.3 Inspections
IRP Daily visual inspection of BOP components for leaks is required. Function tests are to be conducted regularly (as per regulatory requirements). Where a BOP system is found to function improperly an immediate thorough inspection, repair and retest is required.

2.2.7.4 Certification
IRP All metallic BOP components which may be exposed to sour effluent must be certified as being manufactured from materials meeting the requirements of NACE MR0175, latest edition\(^1\).

NOTE: Certification is to be supplied by the component manufacturer. The contractor supplying the BOP equipment must ensure the certification date is current and that any modification or retrofit of BOP systems is completed using components which meet or exceed original equipment
Completing and Servicing Critical Sour Wells

manufacturer specifications. Components may be qualified by third party inspection firms.

2.2.7.5 Maintenance

IRP BOP systems must be shop serviced and overhauled every three years.

Whenever the main flanges or any primary well control component are disassembled, the ring gaskets must be replaced with new gaskets.

2.2.7.6 Testing

IRP BOP equipment must be pressure tested to its working pressure prior to installation.

NOTE: AEUB Information Letter IL 88-11² details shop servicing and testing guidelines for BOP overhaul and maintenance.

Primary well components are those pieces of equipment which will be exposed to well bore effluent on a shut in at the BOP, i.e. the main BOP flanges and inside wing valves.

Testing of non-primary well control components is addressed in the respective recommended practice pertinent to that equipment.

2.2.7.7 Records and Enforcement

IRP All contractors supplying BOP equipment shall maintain documentation pertaining to equipment material certification, testing, repair and maintenance. This data shall be available for review by the operating company and applicable regulatory body as required.

Where such records are not available for the equipment, the equipment must be certified prior to use. Re-certification must be acceptable to the applicable regulatory body and the operating company.
2.2.8 Installation and Operation

2.2.8.1 Assembly and Testing

IRP BOP equipment shall be fully assembled and tested prior to installation on the well. All BOP components shall be pressure tested for 15 minutes each to:

- 1400 kPa, and
- to the working pressure of the BOPs or the formation pressure, whichever is less.

No leaks are acceptable. Tests shall be documented, recorded, and filed for future reference. Assembly on site shall be supervised by qualified personnel with advice, if required, solicited from the component supplier. All BOP tests shall be witnessed by the operator and rig contractor representatives. If any component of the BOP is disassembled (for example, opening of ram gates), a component test and a full BOP body (shell) test is required.

Following initial inspection, BOP components shall be pressure tested monthly to a maximum anticipated working pressure.

2.2.8.2 Function Testing

IRP The primary well control components, with the exception of the shear ram, shall be functioned daily provided it is operationally safe to do so. All function tests and BOP drills are to be recorded on the tour sheet.

NOTE: The function tests may coincide with BOP drills where more than one crew is used on a completion or workover. Crews should be exposed to such function testing on an alternating basis (i.e. daylight crew one day and night crew the next).

2.2.8.3 Handling

NOTE: Since a shear ram will be used on some critical wells, the BOP will be considerably larger than those commonly used on service rigs. The BOP is usually supplied by a third party (rental company) and is usually fully
assembled. The rig crew should be instructed in safe handling procedures for the new equipment. The use of a suitable crane to handle the BOP is recommended. Ensure the stack is stabilized to minimize movement.

2.2.8.4 BOP Procedures

IRP Details of shear ram operation must be posted in the dog house when shear rams are in service, in addition to the standard well control procedures.

NOTE: Although the use of shear rams will likely be a considered as a final attempt at well control, the individuals responsible for shear ram actuation must be totally familiar with the shearing procedure. It is unlikely the use of shear rams can be practiced, as is the case with other well control systems.

2.2.8.5 Alternate Uses of BOPs

IRP On critical wells, BOPs shall not be used for any other function than well control.
APPENDIX A. WELL CONFIGURATION

Figure 1. Critical Sour Well Servicing BOP Stack With Shear Blind Ram
Figure 2. Critical Sour Well Servicing BOP Stack With Shear Blind Ram Optional Arrangement
**Table 1. Material Specifications BOP Components**

<table>
<thead>
<tr>
<th>Key Items</th>
<th>Recommended Minimum Material Standard</th>
<th>Typical Material Types Used</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bodies &amp; Integral Flanges</td>
<td>API 16A(^2) latest edition Temperature Rating -46°C (–50°F)(^\ast) NACE MR0175 latest edition(^\ast)</td>
<td>AISI 4130 or a slightly modified chemistry</td>
<td>Older and lower pressure rated models may be carbon-manganese grade of steel. API 6A should be utilized for qualification of bodies and integral flanges for BOP stacks manufactured prior to January 1988.</td>
</tr>
<tr>
<td>Working Spools</td>
<td>API 16A(^2) latest edition Temperature Rating -46°C (–50°F)(^\ast) NACE MR0175 latest edition(^\ast)</td>
<td>Plain carbon steel pipe such as ASTM A106 or A333 Gr. 6. Flanges may vary from Carbon steel to low alloy steel such as ASTM 4130 to 4145 or AISI 1020 to 1050.</td>
<td></td>
</tr>
<tr>
<td>Internal Components Directly Exposed to Produced or Injected Sour Fluids</td>
<td>NACE MR0175 latest edition(^\ast)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Welding (Both Fabrication &amp; Repairs)</td>
<td>Weld procedures and Welder qualifications to ASME Section IX NACE MR0175 latest edition(^\ast)</td>
<td>AWS E7018</td>
<td>The welding guidelines of IRP 1 (for Drilling Critical Sour Wells) are strongly advised to be followed.</td>
</tr>
</tbody>
</table>
Table 2. Material Specifications BOP Components

<table>
<thead>
<tr>
<th>Key Items</th>
<th>Recommended Minimum Material Standard</th>
<th>Typical Material Types Used</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bolting</td>
<td>NACE MR0175 latest edition** Class II API 6A³ latest edition API 6A Table 49 latest edition Temperature Rating -46°C (-50°F)</td>
<td>Studs: ASTM A320 L7M Nuts: ASTM A194 2 HM</td>
<td>User should be aware that flange size restrictions apply when using reduced yield strength bolting (i.e. A320 L7M) – see Table 49, API 6A, latest edition. To avoid derating, A453 Grade 660 or CRA bolting must be used.</td>
</tr>
<tr>
<td>Ring Joint</td>
<td>API 16A³ latest edition</td>
<td>304 and 316 Stainless Steel</td>
<td>Austenitic stainless steel gasket material NACE MR0175 latest edition** must be in the annealed condition.</td>
</tr>
<tr>
<td>Annular BOP Elastomer</td>
<td>API 16A³ latest edition</td>
<td>NBR (Nitrile) – REFER TO ELASTOMER SECTION 2.11</td>
<td>Low and high temperature performance of elastomers will vary amongst manufacturers, therefore at temperatures below -7°C (+20°F) heating of BOP elements will be required unless otherwise recommended by the manufacturer. refer to IRP 2.11 Guidelines for Selecting Elastomeric Seals, for additional information on Nitrile</td>
</tr>
</tbody>
</table>

* Each component shall meet the charpy impact requirements of Table IV-5 in API 16A, except that the minimum test temperature of -46°C (-50°F) is adequate.
** Refer to latest edition of NACE MR0175
APPENDIX B. SHEAR BLIND RAM GUIDELINES

Critical Sour Well

Residential Density Level (see next page.)

<table>
<thead>
<tr>
<th>Complexity</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Level 1</td>
<td>N</td>
<td>N</td>
<td>C</td>
<td>C</td>
</tr>
<tr>
<td>Level 2</td>
<td>N</td>
<td>N</td>
<td>C</td>
<td>C</td>
</tr>
<tr>
<td>(see next page)</td>
<td>3</td>
<td>N</td>
<td>C</td>
<td>C</td>
</tr>
<tr>
<td></td>
<td>4</td>
<td>C</td>
<td>C</td>
<td>R</td>
</tr>
</tbody>
</table>

R  - Shear blind rams required

N  - Shear blind rams not required

C  - Shear blind rams to be considered by the operator after thoroughly assessing and addressing the following:

- the complexity of the operations to be conducted,
- the risk of problems occurring during the operation,
- the adequacy of procedures and equipment to prevent or mitigate problem, and
- the feasibility of evacuating on-site personnel and nearby residences in the event of a release.

NOTE: The use of shear rams is ultimately the decision of the applicable regulatory body.
Residential Density

1. No residences within the emergency planning radius and, no urban center or public facility within 5 kilometers.

2. Eight or less residences within the emergency planning radius, and no urban center or public facility within 5 kilometers.

3. Thirty two (32) or less residences within the emergency planning radius, and no urban center or public facility within 1.5 kilometers.

4. Greater than 32 residences in the emergency planning radius, or urban center or public facility within 1.5 kilometers.

Urban Centre – a city, town, new town, village, summer village, or other incorporated center, or similar development.

Public Facility - a recreation area such as a campground or a public building such as a rural school or hospitals situated outside of an urban center.
### List of Complexity Factors

<table>
<thead>
<tr>
<th>Group</th>
<th>Factor</th>
<th>Specifics</th>
</tr>
</thead>
<tbody>
<tr>
<td>Formation</td>
<td>(P) Geologic Confidence</td>
<td>Uncertainty in pressures, permeability, and inflow potential</td>
</tr>
<tr>
<td></td>
<td>(P) Pressure</td>
<td>Kill difficulties at pressure gradients &gt; 9.81 kPa/m or BHP &gt; 70 MPa</td>
</tr>
<tr>
<td></td>
<td>(P) Permeability/Fractures</td>
<td>Difficulty in maintaining kill fluid column with fractures or high permeability</td>
</tr>
<tr>
<td></td>
<td>(S) Inflow Potential</td>
<td>High consequences if well not killed</td>
</tr>
<tr>
<td></td>
<td>(S) Adjacent Recovery Methods</td>
<td>Pressure anomalies due to waterflood, gas injection, or tertiary recovery</td>
</tr>
<tr>
<td></td>
<td>(S) Formation Stability</td>
<td>Problems with high fines production/abrasion</td>
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<tr>
<td></td>
<td>(S) Condensates</td>
<td>Complexities in kick detection and control procedures</td>
</tr>
<tr>
<td></td>
<td>(S) Temperature</td>
<td>Sealing difficulties at formation temperature &gt;125 ºC</td>
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<tr>
<td>Operations</td>
<td>(P) Downhole Configuration</td>
<td>Size/space restraints and increased swabbing potential at OD &lt; 114 mm</td>
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<tr>
<td></td>
<td>small diameter restrictions</td>
<td>Difficulties with liners</td>
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<tr>
<td></td>
<td>abrupt diameter restrictions</td>
<td>Size/space restraints and complexity of installation/servicing/removal</td>
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<td></td>
<td>quantity of tools/equipment</td>
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</tr>
<tr>
<td></td>
<td>(P) Program of Operations</td>
<td>material stress considerations</td>
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<tr>
<td></td>
<td>stimulations</td>
<td>number and difficulty of operations</td>
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<tr>
<td></td>
<td>stripping and snubbing</td>
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</tr>
<tr>
<td></td>
<td>(P) Wellbore Condition</td>
<td>limitation on packer placement</td>
</tr>
<tr>
<td></td>
<td>primary cement quality</td>
<td>loss of shut-in capability if pressure exceeds casing burst</td>
</tr>
<tr>
<td></td>
<td>casing burst vs reservoir pressure</td>
<td>limitations on shut-in pressure</td>
</tr>
<tr>
<td></td>
<td>casing integrity</td>
<td>CO₂ or brine content</td>
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<tr>
<td></td>
<td>corrosion restrictions</td>
<td>waxing, hydrating, scaling</td>
</tr>
<tr>
<td></td>
<td>(S) Depth</td>
<td>Difficulties at &gt;3500 m</td>
</tr>
</tbody>
</table>
Completing and Servicing Critical Sour Wells

<table>
<thead>
<tr>
<th>(S) Deviation</th>
<th>Difficulties at deviations &gt;20° or doglegs &gt;5°/30</th>
</tr>
</thead>
<tbody>
<tr>
<td>(S) Workover Fluids</td>
<td>higher solubility with oil base</td>
</tr>
<tr>
<td>gas solubility</td>
<td>increased danger with</td>
</tr>
<tr>
<td>safety aspects</td>
<td>flammable fluids</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>H₂S Content</th>
<th>(P) High H₂S</th>
<th>(S) Low H₂S</th>
<th>H₂S content &gt;20%</th>
<th>H₂S content &lt;20%</th>
</tr>
</thead>
</table>

(P) Primary complexity factor  (S) Secondary complexity factor

NOTE:

If any one of the primary complexity factors for the specific complexity group is applicable, the group is to be rated as “high”. Operator judgment is required when evaluating the affect of the secondary factors with respect to the rating of the group.

**Complexity Level Matrix**

<table>
<thead>
<tr>
<th>Formation Complexity</th>
<th>Operational Complexity</th>
<th>H₂S Content</th>
<th>Complexity Level</th>
</tr>
</thead>
<tbody>
<tr>
<td>High</td>
<td>High</td>
<td>High</td>
<td>4</td>
</tr>
<tr>
<td>High</td>
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<tr>
<td>Low</td>
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<td>1</td>
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</tbody>
</table>
List of References


Further Resources

2.3 DOWNHOLE EQUIPMENT

2.3.1 SCOPE

2.3.1.1 Downhole equipment IRPs have been developed by DACC with consideration for critical sour completions and servicing activities. In producing wells, downhole equipment is installed to enhance production and/or provide for additional well security. The numbers of tools available are too diversified to be individually addressed and have been grouped into commonly recognized categories (e.g. packers, nipples, etc.) The downhole equipment recommendations focus attention on those procedures, which may affect the security of the well.

2.3.1.2 While the recommendations set out in this IRP are meant to allow flexibility, the need to exercise competent, technical judgement is a necessary requirement, to be employed concurrently with its use. While every effort has been made to ensure the accuracy and reliability of the data contained in the IRP and to avoid errors and omissions, DACC, its subcommittees, and individual members make no representation, warranty or guarantee in connection with the publication or the contents of any IRP recommendations and hereby disclaim liability or responsibility for loss or damage resulting from the use of this IRP, or for any violation of any statutory or regulatory requirement with which an IRP recommendation may conflict.

2.3.1.3 In cases of inconsistency or conflict between any of the recommended practices contained in this IRP and applicable legislative requirements the legislative requirements shall prevail.

2.3.1.4 Throughout this section IRPs are highlighted in bold type and the word “shall” or “must” is used. Additional best practices are not highlighted and contain the words “should” or “recommended”.
2.3.2 MECHANICAL PROPERTIES

NOTE: The key mechanical considerations of downhole tools will obviously vary from one tool to the next. Generally speaking, any piece of equipment that forms an integral part of the tubing string should have the same or better mechanical design properties. IRP 2.4, Tubular Goods, should be consulted for all tubing design considerations. Safety factors were not included for every piece of equipment because the manufacturers have already incorporated a safety factor into their design.

Appendix A should be consulted for recommendations related to downhole equipment material metallurgy and IRP 2.11, Guidelines for Selecting Elastomeric Seals, for recommendations about elastomeric seal selection. Appendix B, Corrosion Resistant Alloys Caution Guideline, is included to illustrate the more common corrosive mechanisms which may limit the useful life of CRA materials.

2.3.2.1 Nipples (Inserts), Mandrels, Expansion Joints, Subsurface Tubing Hangers and Sliding Sleeves

IRP Mechanical properties of landing nipples, mandrels, expansion joints, subsurface tubing hangers, and sliding sleeves installed in a tubing string shall be equivalent to the minimum internal yield strength, collapse pressure, compression and tensile load strength required for the tubing string. Nipple inserts, mandrels, expansion joints, subsurface tubing hangers and sliding sleeves shall be rated to at least the maximum anticipated differential pressure with application and installation done in close consultation with the equipment manufacturer.

2.3.2.2 Capillary Tubing

IRP The capillary tubing string shall be designed with a 2.0 safety factor applied to the manufacturer's minimum tensile strength specification, a 1.125 safety factor applied to the collapse pressure rating, and a 1.0 factor applied to the working pressure.

NOTE: Capillary tubing is a delicate system subject to being crushed while running in. There are very limited sizes, materials, and manufacturers available to the industry. The feasibility of an installation must be evaluated within the constraints of currently available equipment. The specified working pressure has been developed by the manufacturer by applying a factor of four to the specified burst pressure.
2.3.2.3 Bridge Plugs, Packers (Permanent and Drillable), and Packer Accessories

IRP Bridge plugs and packers shall be rated to at least the maximum anticipated differential pressure with installation and application design, performed in close consultation with the equipment manufacturer.

These ratings shall be based on materials of construction, casing size and weight and axial loading of the packer as well as calculations using minimum material properties, minimum dimensions, laboratory test data, and appropriate formulas.

The ratings of accessory equipment such as seal assemblies and seal bore extensions for burst, collapse and tensile strength shall be based on calculations using minimum dimensions, minimum material properties, and appropriate formulas plus manufacturer test data.

2.3.2.4 Surface Controlled Subsurface Valves (SCSSV)

IRP Components which form an integral part of the tubing string, (i.e. tubing retrievable valves and landing nipples) shall be of at least equivalent internal yield pressure, collapse pressure, compression and tensile load strength required for the tubing string.

All components of the safety valve and lock mandrel shall be of sufficient strength and composition to ensure the valve functions properly in all well operating environments.

2.3.2.5 Artificial Lift Equipment

2.3.2.5.1 Sucker Rod Pumping

IRP The Modified Goodman Diagram shall be used for the design of axial loading in sucker rods and polished rods.

Attempt to keep all of the sucker rods in tension at all times. This may require the use of sinker bars above the pump.

NOTE: The modified Goodman diagram as shown in Appendix C accounts for dynamic loading, and as such, no design factors need to be applied except the Service Factor.
2.3.2.5.2 Jet Pumping

IRP  The housing of a jet pump shall be of at least equivalent internal yield pressure and collapse pressure to that required for the tubing. The tubing or casing string(s) containing the power fluid shall be designed in burst and collapse to account for the high pressure of the power fluid. The same design factors shall be used for this tubing as for the production tubing.

2.3.2.5.3 Plunger Lift

IRP  Plunger lift lubricators shall have an internal working pressure rating at least equivalent to that required for the wellhead assembly. The design burst pressure shall be at least 1.5 times the maximum working pressure rating.

2.3.3 Operational Procedures

NOTE: The following procedures are an operational guideline for the installation, ongoing maintenance and retrieval of downhole equipment. These procedures are intended to emphasize the well control situations associated with critical sour well operations. For an overview of each tool's application, Appendix D, Downhole Tool Applications should be consulted.

2.3.3.1 Nipples (Inserts), Mandrels, Expansion Joints, Subsurface Tubing Hangers, and Sliding Sleeves

IRP  Landing nipples, mandrels, expansion joints and sliding sleeves shall be installed as needed and where needed in a critical sour well tubing string. Simplicity in design configuration is a significant benefit. Ensure that the threads are compatible with the tubing string and properly cleaned, lubricated and torqued. Ensure that the device is not run upside down and that all components in the tubing string are dimensionally compatible (See Appendix E, Tool Positioning and Number for further discussion on this topic). Equipment must be positioned so that any seals are subject to as little movement as possible to avoid premature leaks.

Nipple inserts shall be installed with sour service wireline. Successful installation and retrieval of inserts is dependent on the insert and the tubular areas above and below, being free of any foreign material such as rubber, sand, scale, iron sulphide, and/or sulphur. Take any and all steps necessary to ensure the profile is clear of obstructions prior to attempting insert installation or removal. Avoid removing an equalizing prong
until the differential pressure is as close as possible to equalization.

Plan for redundancy wherever possible.

If air could be present in the tubing, take steps outlined in IRP 4.0 to eliminate hazards associated with downhole explosions prior to pulling the insert.

2.3.3.2 Capillary Tubing

Extreme care must be taken while running capillary tubing to avoid crushing or puncturing the tube body. The tube shall be run or pulled using a spooling machine and an overhead sheave assembly.

The tubing shall be pressured with hydraulic oil, strapped to the tubing body and equipped with protectors over the tubing collars. Care must be taken to inject only capillary quality liquids to avoid potential plugging. The surface injection pump shall be equipped with a pressure relief valve to avoid bursting the tubing in the event of plugging. The tubing string shall be equipped with a surface check valve (except in cases where the capillary tubing is used in conjunction with subsurface safety valves).

2.3.3.3 Bridge Plugs, Packers (Permanent and Drillable) and Packer Accessories

An annular pack off device (i.e. packer) shall be installed in all critical wells. It is recognized that annular pack off devices may adversely affect the operating efficiency of certain artificial lift installations. In these situations, the annular pack off device may be omitted if alternative forms of corrosion control are employed.

The tubing string shall be spaced out to account for the anticipated forces at each downhole equipment component that would arise from variations in wellbore pressure and temperature.

All packers and accessories shall be dimensionally checked and shop pressure tested to ensure integrity of seal surfaces and connections.
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IRP

All casing must be scraped and/or a gauge ring run prior to running any packer and accessory equipment in a well.

When running packer and accessories into a well with liners, ensure the liner top in free from debris and burrs.

The packer or bridge plug shall not be set in a casing coupling.

When releasing retrievable packers, the packing elements shall be allowed to retract prior to tripping the tubing out of the hole. Also, when tripping the packer out of the hole, the trip speed must be closely monitored so as not to swab the well in.

NOTE: The use of an annular pack off device (i.e. packer) ensures annular integrity. However, in artificial lift installations, annular pack off device may create operating problems such as gas locking, de-waxing or the inability to circulate kill fluid. In these situations, it is more prudent to leave the annular pack off device out of the wellbore. If the annular pack off device is left out in the interest of operating efficiency, additional corrosion control procedures should be implemented.

2.3.3.4 Surface Controlled Subsurface Safety Valves (SCSSV)

An International Standard has been developed by users/purchasers and suppliers/manufacturers of subsurface safety valves for use in the petroleum and natural gas industry worldwide. This International Standard gives requirements and information to both parties in the selection, manufacture, testing, and use of subsurface safety valves.\(^1\)\(^2\)

A surface controlled subsurface safety valve shall be installed in flowing critical sour producing wells when required by local regulation. Alternative forms of wellhead redundancy, such as on-lease kill systems, and reinforced wellhead enclosures may be considered, provided there is enough evidence to prove that the alternative is equally or more effective than the surface controlled subsurface safety valve. Such alternatives should be considered for wells where downhole completion configuration or artificial lift precludes the use of a surface controlled subsurface safety valve.

Surface controlled subsurface safety valves shall be run to a minimum depth of 30 m below casing flange. Valves may have to be set deeper due to physical or operational circumstances. The maximum setting depth shall be selected in close
consultation with the manufacturer to ensure fail-safe close function.

In wireline retrievable SCSSV installations, a flow coupling shall be installed directly above and below the SCSSV nipple. Each flow coupling shall be a minimum of 0.3 m in length. Wireline retrievable SCSSV’s restrict flow up the tubing string causing both turbulence and increased velocity. Flow couplings may help prevent the premature erosion of the tubing in the vicinity of the SCSSV.

Every valve shall be function and leak tested upon installation. The well operator must establish a function test and leak test program with the test frequency tailored to be field or area specific.

Accurate records of the frequency and results of these tests shall be established and maintained by the operator.

A valve failing an operational test requires servicing as soon as possible. Accurate records of the servicing frequency shall be established and maintained by the operator. Documented field service data may allow prediction of the service frequency.

NOTE: The surface controlled subsurface safety valve’s only purpose is to provide for wellhead redundancy in the event of a catastrophic failure. A need may exist to provide for a line of defense against wellhead failures because of potential vulnerability to the erosive and corrosive effects of produced fluids or mechanical failures such as faulty manufacturing or third party damage.

The reliability of a surface controlled subsurface valve will vary from well to well. Where the sealing ability of the SCSSV would be impaired due to downhole conditions (i.e. sulphur deposition) or where the downhole completion configuration cannot easily accommodate SCSSVs, (i.e. wells on artificial lift, concentric dual completions, etc.) alternative protective measures may be used. On lease kill systems and reinforced wellhead enclosures are two systems that may be considered as alternative methods. Usage of alternative methods must be justified by relating their technical effectiveness to that of the surface controlled subsurface safety valve.

A valve set 30 m below ground level normally is adequate protection from catastrophic surface impacts. Valves may have to be set deeper
due to potential earth movement or operating conditions such as sulphur deposition.

A function test is a test of the SCSSV surface equipment under static conditions (i.e. well is shut in). A leak test follows a function test and involves applying a differential pressure across the valve by bleeding off the pressure at the wellhead. A slam test involves shutting the valve in under dynamic conditions. Although this would more accurately simulate a blowout scenario, repeated attempts at slam testing could create stresses that could cause the valve to fail prematurely. Slam testing is an unnecessary procedure.

A valve operating in a critical well environment may be subject to severe corrosion and erosion conditions. Common sense indicates that SCSSV reliability and performance would be improved with regular maintenance (see Appendix F for procedure). Tubing retrievable valves have shown increased reliability compared to wireline retrievable valves and therefore may have longer service interval.

2.3.3.5 Artificial Lift Equipment

NOTE: Special consideration must be given before Artificial Lift is used in critical sour wells. Generally speaking, the risk of blowouts is low because the reservoir pressures are low. Conversely, some artificial lift techniques require use of complicated equipment (or compromises such as no packer), thereby increasing the chance of mechanical failures as well as increasing the workover complexity.

Prior to installing artificial lift, calculate the $\text{H}_2\text{S}$ release rate for the producing formation at its present condition. If depletion is sufficiently advanced, the well may be no longer critical. An application for change of status may be made to the regulatory body. If accepted, install artificial lift in compliance with local standards for sour service.

2.3.3.5.1 Sucker Rod Pumping

IRP The stress level in a sucker rod string shall be determined whenever there is an installation on a new well or whenever there has been a large change in pumping conditions (i.e. water cuts pump speed, pump size).

Techniques shall be employed to reduce wear of sucker rods/tubing. Techniques to consider include:

- use of a tubing anchor,
• use of sinker bars above the pump, and
• sand control techniques and friction reducing mechanisms such as rod centralizers.

In order to reduce the risk of failure due to stress corrosion cracking of sucker rods, consider the use of inhibitors, coatings, special alloy rods, or continuous sucker rod. Special attention must be paid to the coupling area.

Whenever possible, use an insert rod pump instead of a tubing pump.

**NOTE:** Current manufacturing processes of sucker rod end areas results in a product that may be susceptible to stress corrosion cracking.

### 2.3.3.5.2 Jet Pumping
**IRP** Whenever possible in jet pump applications, use a design that allows removal of the nozzle without pulling the tubing.

### 2.3.3.5.3 Electrical Submersible Pumping
**IRP** In electrical submersible pumping, where a packer is required, a means must be provided to allow for filling the tubing with appropriate kill fluid (i.e. if a check valve is used above the pump, it should be removable).

### 2.3.3.5.4 Plunger Lift
**IRP** In plunger lift applications, the catcher/lubricator assembly shall be inspected on a regular basis for fatigue cracks and pressure tested to at least 1.5 times its operating pressure on a yearly basis.

In plunger lift applications, there must be an SSV (surface safety valve) installed between the wellhead and the catcher/lubricator. The upper master valve can be converted to a SSV by installation of an automatic operator on the bonnet assembly.

In plunger lift applications, consideration should be given to eliminating the lubricator by installing the upper bumper assembly in the tubing.
2.3.3.5.5 Gas Lift

In gas lift applications, the gas lift valves shall be fitted with a suitable check valve so that production fluids are isolated from the casing.
# APPENDIX A. METALLURGICAL RECOMMENDATION

## Table 1. Subsurface Workover and Completion Equipment for Critical Sour Wells

<table>
<thead>
<tr>
<th>Item</th>
<th>Equipment Description</th>
<th>Minimum Recommended Standard</th>
<th>Commonly Used Materials</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Landing Nipples &amp; Accessories</td>
<td>NACE MR0175 latest edition</td>
<td>4130-4145 Steel, 22 HRC Max.</td>
<td>See Note #1</td>
</tr>
<tr>
<td>2</td>
<td>Sliding Sleeves</td>
<td>NACE MR0175 latest edition</td>
<td>4130-4145 Steel, 22 HRC Max. &amp; Annealed 300 Series</td>
<td>See Note #1</td>
</tr>
<tr>
<td>3</td>
<td>Capillary Tubing</td>
<td>NACE MR0175 latest edition</td>
<td>316 duplex</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Downhole Injection Mandrels</td>
<td>NACE MR0175 latest edition</td>
<td>Stainless Steel, nickel alloy 825</td>
<td>See Note #1</td>
</tr>
<tr>
<td>5</td>
<td>Expansion Joints</td>
<td>NACE MR0175 latest edition</td>
<td>4130-4145 Steel, 22 HRC Max.</td>
<td>See Note #1</td>
</tr>
<tr>
<td>6</td>
<td>Subsurface Tubing Hanger</td>
<td>NACE MR0175 latest edition</td>
<td>4130-4145 Steel, 22 HRC Max.</td>
<td>See Note #1</td>
</tr>
<tr>
<td>7</td>
<td></td>
<td>NACE MR0175 latest edition</td>
<td>4140 Steel</td>
<td>See Note #3</td>
</tr>
<tr>
<td>8</td>
<td>Bridge Plugs</td>
<td>NACE MR0175 latest edition</td>
<td>Cast Steel, 4130-4145 Steel</td>
<td>See Note #1 &amp; #3</td>
</tr>
<tr>
<td>9</td>
<td>Tubing Anchors</td>
<td>NACE MR0175 latest edition</td>
<td>4140 Steel, 22 HRC Max.</td>
<td></td>
</tr>
<tr>
<td>10</td>
<td>Subsurface Safety Valves</td>
<td>NACE MR0175 latest edition &amp; API Spec. 14A</td>
<td>4140 Steel, Various Stainless Steels</td>
<td>See IRP 2.11 Elastomer Guide &amp; See Note #2</td>
</tr>
<tr>
<td>11</td>
<td>Sucker Rod Pumps</td>
<td>MR0176 76</td>
<td>Chrome Plated Steel</td>
<td>See Note #2</td>
</tr>
<tr>
<td>12</td>
<td>Sucker Rods Polished</td>
<td>API Spec. 11B</td>
<td>Class C &amp; D Grade 97 Chrome Plated 4130-4145 Austenitic or Ferritic Stainless Steels</td>
<td>See Note #4</td>
</tr>
<tr>
<td>13</td>
<td></td>
<td>NACE MR0175 latest edition</td>
<td>4130-4145 Steel, 22 HRC Max.</td>
<td>See Note #1 &amp; #2</td>
</tr>
</tbody>
</table>

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16 Electrical Submersible Pump Cable & Protectors

NACE MR0175 latest edition

Cable = Copper Conductor with Alloy Coating, E.P.D.M. Insulation, Lead Jacket, Nylon braid and Galvanized Steel or Monel Armour Jacket.
Protector = Fluorocarbon Elastomer

E.P.D.M. = Ethylene Propylene Rubber

17 Non-Metallic Seals

TM-01-87-87

Fluorocarbon Type Elastomers & Plastics, Nitrile Packing Elements

See IRP 2.11 Elastomer Guide

General Notes

1. Minimum test methods that should be performed to verify material quality are:
   a) Hardness Test; this test confirms the particular steel is within the acceptable hardness range;
   b) Non-destructive testing to inspect for service or manufacturing defects, (i.e., Magnetic Particle inspection, Liquid Penetrant, Ultrasonics, or Radiography Tests). Detailed Quality Control Procedures with subsurface safety valves are outlined in API Specification 14A.

2. The welding guidelines listed in IRP 1.15 (Industry Recommended Practices for Drilling Critical Sour Wells) are strongly advised.

3. Historically, retrievable equipment that did not meet the previous specifications has been run successfully in critical sour wells. Time of exposure to the environment must be considered.

4. Where design allows, materials that meet the intent of NACE should be used.

5. The focus of the IRP has been to recommend MINIMUM standards for materials to be used for critical sour service. These recommendations are primarily designed to prevent Sulphide Stress Corrosion Cracking because it can result in the “rapid” failure of metals. Similarly (as noted in the NACE MR0175 Specification, latest edition), austenitic stainless steels can fail rapidly from chloride stress corrosion cracking in certain environments. However, the material selection for resisting the many forms of weight loss corrosion is left as an economic decision to be made by the well operator.
APPENDIX B. CORROSION RESISTANT ALLOYS

Caution Guideline

The attached table contains the more commonly used CRA’s, and identifies the more common corrosive mechanisms which adversely limit the useful life of these materials. Included below is a listing of the various CRA groupings and their associated materials specifications. The list is not complete, and hence, this guideline serves to illustrate the considerable importance attached to thoroughly researching one’s specific materials applications.

A. Stainless Steels:

1. Martensitic Stainless Steel (Group I):
   AISI Types 403, 410, 414, 416, 420, 422, 431, 440A, 440B, 440C

2. Ferritic Stainless Steel (Group II): AISI Types 405, 430, 442, 443, 446, 501, 502 ASTM, A268


4. Corrosion (C) Resistant Alloys. (Cast Alloys):

   NOTE: The ACI designations below have equivalent AISI designations as depicted in (1), (2) and (3) immediately above. These should be cross-referenced, if any doubt exists. The corrosion resistance of cast alloys is similar to, but not identical to, that of the wrought stainless steels. Consequently, the attached table must only be used as a general reference for the cast materials.


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B. Duplex Stainless Steels:

1. Austenite/Ferrite:

<table>
<thead>
<tr>
<th>Material</th>
<th>Composition</th>
</tr>
</thead>
<tbody>
<tr>
<td>SAF 2205</td>
<td>NK CR 22</td>
</tr>
<tr>
<td>Sanicro 28</td>
<td>SM 22 CR</td>
</tr>
<tr>
<td>Alloy 20</td>
<td>AF 22</td>
</tr>
<tr>
<td>CD4Mcu</td>
<td>VS 22</td>
</tr>
<tr>
<td>Ferrallium 255</td>
<td>Cronifer 22-5 LCN</td>
</tr>
<tr>
<td>CN7M</td>
<td>NK 255</td>
</tr>
<tr>
<td>CF8</td>
<td>SM 25 Cr (DP-3)</td>
</tr>
</tbody>
</table>

C. Precipitation Hardening Stainless Steels (Group IV):

Types: 7-4PH, 17-7PH, 17-10P
PM 15-7 Mo, Stainless W, AM 350
AM 355, HNM, Maraging (18-250)

D. Titanium Alloys:

1. A - Alloys
2. B - Alloys
3. A, B – Alloys

E. "Named" Proprietary Steels and Nickel Alloys:

<table>
<thead>
<tr>
<th>Steel Type</th>
<th>Material</th>
<th>Composition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Armco Iron</td>
<td>Durimet-20</td>
<td>Ni Hard (No.1)</td>
</tr>
<tr>
<td>Carpenter-20</td>
<td>Hastelloy B</td>
<td>Ni Resist (No.1)</td>
</tr>
<tr>
<td>Chlorimet-2</td>
<td>Hastelloy C-276</td>
<td>Zircaloy-2</td>
</tr>
<tr>
<td>Chlorimet-3</td>
<td>Hastelloy X</td>
<td>Inconel 718</td>
</tr>
<tr>
<td>Croloy-2</td>
<td>Incoloy (802)</td>
<td>Incoloy 925</td>
</tr>
<tr>
<td>Croloy-5</td>
<td>Inconel 600</td>
<td>Incoloy 825</td>
</tr>
<tr>
<td>Duranickel (301)</td>
<td>Nichrome V</td>
<td>Inconel 625</td>
</tr>
</tbody>
</table>

F. Nickel-Copper Alloys:

"K" Monel, "R" Monel, "M" Monel, Cast Monel, "S" Monel, Monel
Further Resources for Appendix B


Table 1. Corrosion Resistant Alloys – Caution Guideline (for High Alloy and Non-Ferrous Steels)

<table>
<thead>
<tr>
<th>Corrosive Environment</th>
<th>Ferritic Stainless</th>
<th>Martensitic Stainless†</th>
<th>Austenitic Stainless</th>
<th>Duplex Stainless</th>
<th>Precipitation Hardened</th>
<th>Titanium</th>
<th>Proprietary and “Named”</th>
<th>Nickel – Copper</th>
</tr>
</thead>
<tbody>
<tr>
<td>H₂S (Wet)</td>
<td>SCC if not in NACE cond.</td>
<td>SCC if not in NACE cond.</td>
<td>Good</td>
<td>Good</td>
<td>Must be in NACE cond.</td>
<td>Good</td>
<td>Good</td>
<td>Moderate to Good</td>
</tr>
<tr>
<td>H₂SO₄ (10%)</td>
<td>50+ mpy</td>
<td>Severely pitted</td>
<td>79 mpy§</td>
<td>Attacked</td>
<td>Attacked</td>
<td>Attacked</td>
<td>Good</td>
<td>Good</td>
</tr>
<tr>
<td>HCl</td>
<td>50+ mpy</td>
<td>Severely pitted</td>
<td>Severe pitting</td>
<td>Pitted</td>
<td>Pitted</td>
<td>Pitted &amp; SCC</td>
<td>Good below 5% (vol)</td>
<td>Attacked</td>
</tr>
<tr>
<td>HF</td>
<td>50+ mpy</td>
<td>Severely pitted</td>
<td>Poor</td>
<td>Poor</td>
<td>Poor</td>
<td>Poor</td>
<td>Resistant</td>
<td>Attacked</td>
</tr>
<tr>
<td>Formic Acid (10% vol)</td>
<td>50+ mpy</td>
<td>Severely pitted</td>
<td>590 mpy</td>
<td>NO DATA</td>
<td>NO DATA</td>
<td>Good</td>
<td>Good</td>
<td>Attacked</td>
</tr>
<tr>
<td>H₂CO₃ (CO₂)</td>
<td>Good</td>
<td>Fair to good</td>
<td>Good</td>
<td>Good</td>
<td>Good</td>
<td>High Temperature Caution</td>
<td>50+ mpy @ high T. 2-20 mpy</td>
<td>Good</td>
</tr>
<tr>
<td>Caustic</td>
<td>50+ mpy</td>
<td>Poor</td>
<td>SCC</td>
<td>Good</td>
<td>High Temperature Caution</td>
<td>50+ mpy</td>
<td>Good</td>
<td>Good</td>
</tr>
<tr>
<td>Br</td>
<td>Fair to Good</td>
<td>Poor</td>
<td>Pitted</td>
<td>NO DATA</td>
<td>NO DATA</td>
<td>Poor</td>
<td>Attacked</td>
<td>NO DATA</td>
</tr>
<tr>
<td>Cl</td>
<td>Some pitting Good</td>
<td>SCC</td>
<td>SCC</td>
<td>Good</td>
<td>SCC</td>
<td>SCC</td>
<td>Good</td>
<td>Pits under oxidizing conditions</td>
</tr>
<tr>
<td>Cl₂ (g)</td>
<td>NO DATA</td>
<td>Poor</td>
<td>120-420 mpy</td>
<td>Good</td>
<td>NO DATA</td>
<td>50+ mpy</td>
<td>Poor</td>
<td></td>
</tr>
<tr>
<td>NH₄OH</td>
<td>2 mpy to 20 mpy 100 f</td>
<td>poor</td>
<td>Good</td>
<td>Good</td>
<td>Good</td>
<td>2 mpy</td>
<td>Good</td>
<td>Good</td>
</tr>
<tr>
<td>pH</td>
<td>Feasible range 3 - 10</td>
<td>Feasible range 3-10</td>
<td>Better in Alkaline condition</td>
<td>Good</td>
<td>Below pH 1 SCC</td>
<td>Poor @ low pH</td>
<td>Good</td>
<td>Good</td>
</tr>
<tr>
<td>Galvanic</td>
<td>Yes (to carbon steel)</td>
<td>Yes (to carbon steel)</td>
<td>Yes (to carbon steel)</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>(CH₃)₂S₂‡</td>
<td>Pitted</td>
<td>Pitted</td>
<td>Pitted</td>
<td>Pitted</td>
<td>Pitted</td>
<td>Good</td>
<td>Good</td>
<td>Minor attack</td>
</tr>
<tr>
<td>NaCl</td>
<td>Minor Pitting</td>
<td>SCC</td>
<td>Pitted &amp; SCC</td>
<td>Pitted</td>
<td>Pitted</td>
<td>SCC if precracked</td>
<td>Good</td>
<td>Good</td>
</tr>
</tbody>
</table>

*Corrosive inhibitor free  † Assumes annealed condition  ‡ Denotes DMDS  § Denotes milli-inchers per year

Cautionary Note: This guideline is not a materials selection document, rather it should be used as an aid to the corrosion and/or production engineer for permitting reasonable discussion/consideration for the implications of certain material’s use and more importantly, whether further laboratory study is justified in advance of a questionable material’s actual field use.
APPENDIX C. SERVICE EQUIPMENT

Figure 1. Modified Goodman Diagram

\[ SF = \text{SERVICE FACTOR} \]

\[ T = 1.75 \]

\[ S_A = \frac{1}{4} + M S_{\text{MIN}} SF \]

\[ S_A = (0.25T + 0.5625) S_{\text{MIN}} SF \]

\[ \Delta S_A = S_A - S_{\text{MIN}} \]

WHERE:
- \( S_A \) = MAXIMUM ALLOWABLE STRESS, N/mm²
- \( \Delta S_A \) = MAXIMUM ALLOWABLE RANGE OF STRESS, N/mm²
- \( M \) = SLOPE OF \( S_A \) CURVE = 0.5625
- \( S_{\text{MIN}} \) = MINIMUM STRESS, N/mm² (CALCULATED OR MEASURED)
- \( SF \) = SERVICE FACTOR
- \( T \) = MINIMUM TENSILE STRENGTH, N/mm²

REFERENCE: API RECOMMENDED PRACTICE 11BR,
APPENDIX D. DOWNHOLE TOOL APPLICATIONS

Downhole tools used in critical sour oil and gas producing wells include all types of equipment installed below the wellhead, not including tubing and casing, whose purpose it is to facilitate or enhance production or acts to protect, control or guard against the escape of reservoir fluid at surface as a result of a wellhead or tubing string failure.

The specific downhole tools investigated in this sub-committee and their primary use(s) are itemized in the following table:
### Table 1. Downhole Tool Applications

<table>
<thead>
<tr>
<th>Downhole Equipment</th>
<th>Production</th>
<th>Well Security</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Enhancement</td>
<td>Monitoring</td>
</tr>
<tr>
<td>Landing Nipples (Nipple Inserts Incl. Hook Wall Plugs)</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Sliding Sleeves</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Capillary Tubing</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Downhole Injection Mandrels</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Expansion Joints</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Subsurface Tubing Hanger</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Bridge Plugs (Retrievable and Permanent)</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Packer (Retrievable and Permanent)</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Tubing Anchors</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Subsurface Safety Valves (SCSSV)</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>Sucker Rod Pumping (Sucker Rods, Pump, Sinker Bar, Scrapers, Centralizers, Drain Valve, Check Valve)</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>Jet Pump Nozzle</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Hydraulic Pump</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Gas Lift Mandrel</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Plunger Lift (Plunger, Bumper Spring, Catcher &amp; Lubricator Assembly)</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>Electric Submersible Pump (Pump, Motor, Separator, Cable &amp; Protectors, Check &amp; Drain)</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>Progressive Cavity Pump</td>
<td>X</td>
<td></td>
</tr>
</tbody>
</table>
Downhole Applications Legend

1 Production Enhancement

Production enhancement equipment is installed for the purposes of enhancing production. Its absence does not mean that production would cease but certainly the well could experience problems associated with hydrate or sulphur plugging or reduced deliver abilities caused by unfavorable flow regimes. The following pieces of equipment are installed to enhance fluid flow.

1.1 Landing Nipples - Downhole chokes can be installed in landing nipples to expand the gas and thereby prevent hydrate formation. Nipples can also be used to insert various forms of artificial lift equipment.

1.2 Sliding sleeves - Sleeves may or may not have incorporated a landing profile. If the profile was present it would perform similarly to a landing nipple. The sleeve’s primary purpose is to shut off or open intervals (formations) for production. This provides for enhanced downhole flexibility.

1.3 Capillary Tubing - This piece of equipment can be used to inject various fluids that can help to prevent corrosion, hydrate or sulphur plugging.

1.4 Downhole Injection Mandrels - By installing a downhole valve, gas can be injected to artificially lift fluid to surface. It can also be used to segregate or open intervals to flow similar to a sleeve. By incorporating a string of capillary tubing various fluids can be injected to prevent corrosion, hydrate or sulphur formation.

1.5 Bridge Plugs - They can be used in association with a packer to selectively stimulate intervals. They are also installed to isolate intervals or formations.

1.6 Packers - The installation of a packer reduces the surface area to flow and thereby can provide for a more favorable flow regime (especially in the case where liquids are being produced).

Packers also perform similar functions to those of bridge plugs and these two tools are often found in association with one another.

1.7 Tubing Anchors - Placing the tubing in tension makes downhole rod pumps perform more efficiently and this helps to promote production.

1.8 Artificial Lift (Rod, Jet and Hydraulic Pumps, Gas and Plunger Lift, Submersible and Progressive Cavity Pump) - All artificial lift equipment is used to enhance production by supplementing the reservoir energy. They are normally found when
predominately liquids are being produced.

2 Production Monitoring

Production monitoring usually involves the incorporation of equipment to collect data on a well's performance. This data is usually in the form of pressure information but can also include temperature and flow information as well.

2.1 Landing Nipples, Sliding Sleeves, Expansion Joints and Downhole Injection Mandrels All of these pieces of equipment may have profiles which can be used to land pressure and temperature recording devices.

2.2 Capillary Tubing By injecting nitrogen, for example, continuous downhole pressure measurements can be obtained.

3 Temporary Suspension

A temporary suspension involves the isolation of a particular formation interval or formation downhole.

Profiles found in landing nipples, sliding sleeves, downhole injection mandrels, expansion joints, packers, and subsurface safety valves can, with the insertion of a check valve or blanking plug, be used to isolate an interval from flowing into the tubing string.

Bridge plugs are inserted normally in the casing (although they can also be installed in the tubing) to isolate a particular interval or formation.

4 Permanent Abandonment

Abandonments normally involve the use of downhole tools to permanently isolate a formation from all future production. They involve completely sealing off the casing above the formation selected for abandonment. For a well to be formally abandoned, cement must also be applied immediately above the tool. (A minimum of 8 metres of cement or 2 metres of resin/gypsum blend.)

Bridge plugs or packers with a landing profile and blanking plug are commonly used to abandon formations.

5 Equipment Failure

There are pieces of equipment that are installed either to assist in preventing a tubing string failure or to act to contain fluid flow in the event of a wellhead failure.
5.1 Capillary Tubing and Downhole Injection Mandrels - Inhibitors can be injected to help mitigate corrosion.

5.2 Expansion Joints - Tubing stresses can be relieved significantly by the incorporation of an expansion joint into the string

5.3 Subsurface Tubing Hanger - If an up-hole modification of the tubing assembly is planned, a tubing hanger can be employed.

5.4 Tubing Anchors - This piece of equipment is used to prevent tubing movement in pumping wells and may relieve tubing fatigue.

5.5 Subsurface Safety Valves - In the event of a wellhead failure, subsurface safety valves would act to contain the flow of fluids.

6 Corrosion Mitigation

Certain tools can be used either directly or indirectly to help slow down the corrosion that occurs in every well.

6.1 Capillary Tubing or Downhole Injection Mandrels - These two pieces of equipment either independently or in association with one another can be used to inject inhibitors either continuously or batched.

6.2 Sliding Sleeves, Downhole Injection Mandrels, Bridge Plugs and Packer - This equipment can be used to physically isolate a corrosive interval from a corrosion sensitive area such as a tubing - casing annulus.
APPENDIX E. TOOL POSITIONING AND NUMBER

Every tool installed in a well has an application. Some tools have many applications. The types of tools selected and their number often times is a compromise between all of the variables considered in the design. The recommendations itemized in the attached table were designed for typical flowing and pumping well scenarios (see attached bottomhole diagrams). They should only be used as a guide when making design decisions. Well conditions may create situations which alter the design significantly enough that it falls outside of the guideline.

Table 1. Tool Positioning And Number – (Flowing Gaswell Scenario)

<table>
<thead>
<tr>
<th>Downhole Equipment</th>
<th>Minimum Number</th>
<th>Positioning</th>
<th>Justification</th>
</tr>
</thead>
<tbody>
<tr>
<td>Landing Nipples</td>
<td>2**</td>
<td>One below the packer separated by a length of tubing and one immediately above the packer (preferably in an on-off connector).</td>
<td>Two nipples provides for redundancy. The nipples below the packer can be used for well suspension purposes. If the blanking plug cannot be removed, the length of tubing below the packer can be cut off with a cutter. The nipple above the packer would help act as a back-up to the nipple below the packer. If future workovers are planned, a plug set in a seal area recess can be an asset as it is more easily retrievable.</td>
</tr>
<tr>
<td>Sliding Sleeve</td>
<td>Optional*</td>
<td>As deep in the well as required. Normally immediately above the packer.</td>
<td></td>
</tr>
<tr>
<td>Capillary Tubing</td>
<td>Optional*</td>
<td>Full length and strapped to the outside of the production tubing string.</td>
<td></td>
</tr>
<tr>
<td>Downhole Injection Mandrels</td>
<td>Optional*</td>
<td>As deep in the well as required. Normally immediately above the packer.</td>
<td></td>
</tr>
<tr>
<td>Expansion Joints</td>
<td>Optional*</td>
<td>As deep in the well as required. Normally</td>
<td></td>
</tr>
<tr>
<td>Component</td>
<td>Quantity</td>
<td>Description</td>
<td></td>
</tr>
<tr>
<td>---------------------------------</td>
<td>----------</td>
<td>--------------------------------------------------------------------------------------------------------------------------------------------</td>
<td></td>
</tr>
<tr>
<td>Subsurface Tubing Hanger</td>
<td>Optional*</td>
<td>Immediately above the packer. Uphole below the subsurface safety valve.</td>
<td></td>
</tr>
<tr>
<td>Bridge Plug</td>
<td>Optional*</td>
<td>In the first full joint above the perforations where there is good cementation. Within 15m of the top perforation to be abandoned.</td>
<td></td>
</tr>
<tr>
<td>Packer</td>
<td>One**</td>
<td>As deep in the well as practical. Preferably in a full casing joint with the tailpipe bottom above the top perforations in order to facilitate future anticipated logging and perforating operations. Set in an area of well cemented pipe and never in a casing collar recess. To protect the tubing to casing annulus thereby creating redundancy.</td>
<td></td>
</tr>
<tr>
<td>Tubing Anchor</td>
<td>Optional*</td>
<td>As deep in the well as possible. Land above the perforations.</td>
<td></td>
</tr>
<tr>
<td>Subsurface Safety Valve</td>
<td>One**</td>
<td>30m minimum or down to the area of the packer depending on the type of valve chosen.</td>
<td></td>
</tr>
<tr>
<td>Artificial Lift</td>
<td>Optional*</td>
<td>Usually set as deep in the well as possible except in the case of gas lift mandrels, which will be spaced out throughout the entire string of tubing.</td>
<td></td>
</tr>
</tbody>
</table>

* These materials should be kept to a minimum to reduce well complexity. Their primary purpose is not one of well security but rather to enhance production.  
** These recommendations may not apply to artificial lift scenarios.
APPENDIX F. TEST PROCEDURES FOR INSTALLED SURFACE CONTROLLED SUBSURFACE SAFETY VALVES (SCSSV)

A. FUNCTION TEST

1. Record the control pressure.

2. Isolate the control system from the well to be tested.

3. Shut the well in at the wellhead.

4. Wait a minimum of five minutes. Check the control line for loss of pressure, which may indicate a leak in the system.

5. Bleed the control line pressure to zero to shut-in the SCSSV. Close in the control line system and observe for pressure build-up, which may indicate faulty SCSSV system. If such pressure build-up occurs, corrective action should be taken.

B. LEAK TEST

1. Bleed the pressure off the wellhead to the lowest practical pressure and then shut-in the well at the wing or flowline valve. When possible, bleed flowline header pressure down to, or below, wellhead pressure and observe the flowline and wellhead for a change in pressure, which would indicate a faulty surface valve. Any leaks through the wing, or flowline valve, must be repaired before proceeding with the rest.

2. Observe the tubing pressure build-up for one hour or measure flow from the well. Record and report leakage rate. For gas wells, flow rate can be computed from pressure build-up by the formula:

\[
Q = 2122 \left( \frac{AP}{AZ} \right) \left( \frac{1}{\Delta t} \right) \left( \frac{V}{T} \right)
\]

\[
Q = 17068 \left( \frac{AP}{AZ} \right) \left( \frac{1}{\Delta t} \right) \left( \frac{V}{T} \right) \quad \text{(SI Units)}
\]

Where \(Q\) is the leakage rate SCF/hr (m³/hr).
$\Delta P/Z$ is the final P (pressure in psia) (Bar) divided by final Z (gas deviation factor) minus initial P divided by initial Z.

$\Delta t$ is the build-up time in minutes to reach a stabilized pressure.

$V$ is the volume of the tubing string above the SCSSV in cubic feet ($m^3$).

$T$ is the absolute temperature at the SCSSV

$(\text{Deg F} + 460) (\text{oC} + 273.0)$.

For low pressure applications this formula may be simplified as follows:

$$Q = \frac{4 (\Delta P) Z}{\Delta t}$$

$$Q = \frac{58.1 (\Delta P) V}{\Delta t} \quad \text{(SI Units)}$$

For oil wells, the pressure build-up depends on the static fluid level and the amount of gas in the oil. If the fluid level is below the SCSSV, the formula for gas wells can be used. If the fluid level is above the SCSSV, the leakage rate should be measured.

3. If the SCSSV failed to close or if the leakage rate exceeds 25.5$\text{m}^3$/hr (0.4 $\text{m}^3$/min) gas or 400cc/min liquid, corrective action should be taken.

4. After the SCSSV tests successfully use the manufacturer’s recommended reopening procedure.

5. When the SCSSV has been determined to operate properly and is opened, the control line pressure must be tied back into the system control pressure and the well can be placed back on production. Check well test rate. A significant reduction in the well test rate may be the result of the SCSSV not reopening fully.
List Of References


2.4 Tubular Goods

2.4.1 Scope

2.4.1.1 Tubing design requirements are presented which include recommended design factors for burst, collapse, tension and fibre stress. Recommendations are presented respecting tubular metallurgy and threaded connectors. A manufacturer pre-qualification protocol plus test procedures and acceptance criteria are given which should ensure that tubing resistant to environmental embrittlement mechanisms is obtained. Quality assurance and running and handling procedures are addressed. For the production phase of the well, corrosion monitoring and control are discussed.

2.4.1.2 Throughout this section, IRPs are highlighted in bold type and usually contain words “shall” or “must”. Additional best practices contain the words “should” or “recommended”.

2.4.2 Design Requirements

2.4.2.1 General Requirements

Tubing strings should be designed to minimize the potential for servicing or workover operations.

NOTE: The failure of a tubing string is not sufficient in itself to result in an immediate release of sour gas. However, AEUB data indicates that a significant percentage of non-drilling blowouts occur during servicing operations. The need or potential for servicing operations on critical sour wells should therefore be minimized through prudent tubing design.

2.4.2.2 Tubing Stress Conditions

Variations in fluid pressures, temperature, and densities should be considered to account for all potential tubing movements. Tubing movements, when restrained by a packer, should be converted to an equivalent force and included in the tubing string analysis.

Tubing design should have consideration for packer design and limitations to ensure that length variations do not result in the tubing leaving the packer seal bore (stung or landed tubing) and do not result in sufficient forces to unseat the packer (landed or latched tubing). Similar considerations should be given to tubing completed with a tubing anchor.
Tubing design should incorporate realistic worst-case operational parameters as follows:

- Tubing restraints considered as a latched tubing packer arrangement (unless the operator is confident the tubing is free to move with relation to the packer).
- Temperature considerations under maximum production rates (both friction and gas expansion can contribute to temperature effects).
- Pressure differentials across the tubing and across the packer for both initial production and depleted reservoir production.

Wells to be stimulated should include the following design parameters:

- Stimulation fluid temperature at bottomhole equals surface temperature, or as derived from a computer simulation.
- Maximum surface pressure based on maximum allowable surface treating pressure.
- Fluid density equals maximum fluid density present in the wellbore at any time during the stimulation.
- Pressure drops due to friction ignored to allow for sandoff conditions if pumping proppant.

**2.4.2.3 Tubing Design Criteria**

Tubing design criteria should include the following under the aforementioned stress conditions:

- **Tension**: evaluated at the top joint of the tubing string and at all points of tubing size/weight/grade crossover with respect to the lesser of the tensile strength of the tubing body or coupling.
- **Burst**: evaluated at surface and the bottom joint (i.e. at packer), as well as all points of size/weight/grade crossover.
- **Collapse**: evaluated at surface and the bottom joint (i.e. at packer), as well as all points of size/weight/grade crossover.
- **Maximum Principal Triaxial Stress** (sometimes called maximum fibre stress): evaluated at surface and the bottom joint (i.e. at packer), as well as all points of size/weight/grade crossover. In the lower (corkscrewed) stress portion of the string, analyze at the outer fibre under setdown conditions and at both the inner and outer fibre under producing and stimulation conditions.
2.4.2.4 Design Factors

IRP Tubing design shall meet or exceed the following design factors:

Tension = 1.25
Burst = 1.25
Collapse = 1.0
Maximum Principal Stress = 1.25

IRP Design factors shall be calculated based on tensile strengths, burst resistances and collapse resistance as prescribed in API Bulletin 5C2\(^{1}\). The collapse rating must be reduced when the tubing is subject to axial (tensile) stress as per API Bulletin 5C3\(^{2}\). The maximum principal stress design factor shall be calculated based on the Specified Minimum Yield Strength (SMYS) of the material.

Premium connection burst, collapse and tensile ratings not listed by API should be obtained directly from the manufacturer.

Design factors for workstrings, while the critical zone is open, shall meet or exceed the values listed above and should include appropriate overpull provisions.

2.4.3 Manufacturing and Inspection

2.4.3.1 Introduction

Carbon or low alloy steel tubing in excess of 655 MPa SMYS, internally-coated or clad tubing, and corrosion resistant alloy (CRA) tubing are beyond the scope of this Recommended Practice.

IRP Where an alternate grade of carbon steel or CRA material is desired, the philosophy of thorough verification, testing, and inspection outlined in this document shall be employed under the supervision of a qualified technical expert.

Both seamless and ERW tubulars may be acceptable for critical sour wells. Each manufacturing method has its own shortcomings and therefore, the onus must remain on the operator to satisfy that the pipe will be suitable for the intended service.

This specification is intended to supplement the requirements of API 5CT\(^{3}\). In all cases, API 5CT is the basic specification to which the following enhancements are recommended.
This specification is a minimum requirement and further improvements may be advisable, especially in wells with severe operating conditions. Unless otherwise specified, this specification applies to coupling stock as well as the pipe body.

Sour gas contains hydrogen sulfide ($\text{H}_2\text{S}$) and carbon dioxide ($\text{CO}_2$) at various partial pressures and ratios. These gases make any aqueous environment present acidic and potentially corrosive. In addition, the presence of hydrogen sulfide may make the tubing and coupling materials susceptible to environmental embrittlement mechanisms. This IRP addresses three environmental degradation mechanisms that may be active when tubing and couplings are exposed to sour gas:

- **Sulfide Stress Cracking (SSC)**, which may be active in all tubing and coupling grades listed.

- **Hydrogen-Induced Cracking (HIC)**, which may be active in grade J55 tubing and grade K55 casing (used as production tubing) manufactured by either the seamless or the electric resistance welding process. Quenched and tempered microstructures typically have high resistance to HIC. Tensile stress is not necessary for the initiation and growth of HIC.

- **Stress-Oriented Hydrogen-Induced Cracking (SOHIC)**, which also may be active in grades J55 and K55 (used as tubing), manufactured by either the seamless or the electric resistance welding process. Quenched and tempered microstructures typically have high resistance to SOHIC. SOHIC appears to be a combination of HIC and SSC.

SSC may occur very quickly (minutes to hours) upon exposure of susceptible tubing and couplings to sour gas, depending on the level of tensile stress (residual and operating), the temperature, the acidity (pH) of the aqueous environment, the partial pressure of $\text{H}_2\text{S}$, and the inherent resistance of the material. SOHIC and HIC are more time-dependent mechanisms, though failure by SOHIC may occur within two days in highly susceptible material.

Adherence to this IRP should ensure that tubing and couplings with adequate resistance to SSC, HIC and SOHIC would be obtained under normal stressing and environmental exposure situations.
2.4.3.2 Implementation

**IRP** All new tubing used in critical sour wells and manufactured more than one year after the publication of this document, shall meet the specifications outlined in IRP 2.4.3

2.4.3.3. General Manufacturing Guidelines

This IRP refers to grades of tubing and couplings referenced in the American Petroleum Institute’s “Specification for Casing and Tubing”, API 5CT\(^3\).

The following grades listed in API 5CT are intended for general sour gas exposure at any temperature:

- J55 (seamless or electric resistance-welded).
- K55 casing used as tubing (seamless or electric resistance-welded).
- L80 type 1 (seamless or electric resistance-welded).
- C90 type 1 (seamless)
- T95 type 1 (seamless)

**IRP** The grades listed above are acceptable for use in critical sour gas wells provided that the additional chemical composition, testing, inspection, marking, and documentation requirements identified in this IRP have been met.

**IRP** J-55 and K-55 ERW tubing shall be full body normalized. Cold upset ends on seamless tubing for L-80 grades and higher shall be stress relieved.

**NOTE:** For hot upset pipe, controlled cooling after upsetting is advised to provide consistent mechanical properties.

2.4.3.4 Chemical Composition

Tubing and couplings made from steel meeting the minimum chemical composition requirements of API 5CT for the particular grade will not necessarily have adequate resistance to sulfide stress cracking when used in critical sour gas wells.

**IRP** The following product analysis chemical composition requirements shall be specified for critical sour gas well tubing and couplings (by grade, maximum or permitted range, in weight %):
NOTE: The specifications recommended in this IRP have been developed with consideration to both proprietary specifications and mill capabilities. In all cases, improvements to API 5CT are within current mill capabilities, are within economic limits, and provide a significant increase in the performance of these tubulars in a critical sour gas well environment.

Table 2.4.1 Chemical Composition Requirements

<table>
<thead>
<tr>
<th>Element</th>
<th>J55/K55</th>
<th>L80 type 1</th>
<th>C90 type 1</th>
<th>T95 type 1</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbon</td>
<td>0.35</td>
<td>0.35</td>
<td>0.35</td>
<td>0.35</td>
</tr>
<tr>
<td>Manganese</td>
<td>1.50</td>
<td>1.40</td>
<td>1.00</td>
<td>0.75</td>
</tr>
<tr>
<td>Silicon</td>
<td>0.35</td>
<td>0.35</td>
<td>0.35</td>
<td>0.35</td>
</tr>
<tr>
<td>Phosphorus</td>
<td>0.020</td>
<td>0.020</td>
<td>0.015</td>
<td>0.010**</td>
</tr>
<tr>
<td>Sulfur</td>
<td>0.010</td>
<td>0.010</td>
<td>0.010</td>
<td>0.005</td>
</tr>
<tr>
<td>Chromium</td>
<td>*</td>
<td>1.30</td>
<td>1.20</td>
<td>0.40 - 1.20</td>
</tr>
<tr>
<td>Molybdenum</td>
<td>*</td>
<td>0.65</td>
<td>0.75</td>
<td>0.15 - 0.85</td>
</tr>
<tr>
<td>Copper</td>
<td>0.20</td>
<td>0.20</td>
<td>0.20</td>
<td>0.15</td>
</tr>
<tr>
<td>Nickel</td>
<td>0.20</td>
<td>0.20</td>
<td>0.20</td>
<td>0.15</td>
</tr>
<tr>
<td>Aluminum</td>
<td>0.040</td>
<td>0.080</td>
<td>0.040</td>
<td>0.040</td>
</tr>
<tr>
<td>Niobium</td>
<td>*</td>
<td>0.040</td>
<td>0.040</td>
<td>0.040</td>
</tr>
<tr>
<td>Vanadium</td>
<td>*</td>
<td>*</td>
<td>0.050</td>
<td>0.050</td>
</tr>
<tr>
<td>Titanium</td>
<td>*</td>
<td>0.040</td>
<td>0.040</td>
<td>0.040</td>
</tr>
<tr>
<td>Boron</td>
<td>*</td>
<td>0.0030</td>
<td>0.0030</td>
<td>0.0030</td>
</tr>
</tbody>
</table>

* Not normally added to this grade.

** P maximum may be increased to 0.015 % if there is a minimum of 0.30 % Mo.

The chemical composition requirements for electric resistance-welded J55/K55 may need to be more restrictive than specified above to ensure resistance to HIC and SOHIC. Typically, lower levels of C, Mn, P and S than the maximum specified in the table are required to impart resistance to HIC and to SOHIC. In addition, calcium treatment may be necessary to eliminate elongated type II manganese sulfide inclusions. These inclusions have been associated with HIC development.

IRP The tubing and coupling specification shall require that the manufacturer be requested not to add any elements not listed in the above table without the prior written consent of the purchaser.

These and other requirements listed in subsequent clauses of this IRP essentially mean that the manufacturer will need to provide proprietary grades of tubing and couplings for critical sour gas wells. These materials should be dual stamped with the API monogram and the manufacturer’s proprietary grade identification/name.
2.4.3.5 Tensile Testing

IRP Mechanical property requirements shall be per API 5CT. The frequency of testing shall be as follows for non-upset pipe:

Table 2.4.2 Tensile Testing Frequency

<table>
<thead>
<tr>
<th></th>
<th>J55/K55</th>
<th>L80 type 1</th>
<th>C90 type 1</th>
<th>T95 type 1</th>
</tr>
</thead>
<tbody>
<tr>
<td>Frequency</td>
<td>Per API 5CT for Group 1</td>
<td>1/200 pipes or once per heat or lot*, alternating ends</td>
<td>1/100 pipes or two per heat or lot*, alternating ends</td>
<td>1/100 pipes or two per heat or lot*, alternating ends</td>
</tr>
<tr>
<td>Frequency</td>
<td>Per API 5CT for Group 1</td>
<td>1/100 pipes or once per heat or lot*, alternating ends</td>
<td>Per API 5CT for Group 2</td>
<td>Per API 5CT for Group 2</td>
</tr>
</tbody>
</table>

* Whichever is more frequent

For upset tubing, two samples shall be tested per the frequency in the above table. One sample shall be taken from the pipe body and the other sample shall be taken from the upset. Both samples shall be removed from the tubing after all heat treatment has been completed. The test method shall be per API 5CT.

2.4.3.6 Hardenability Testing

There are no hardenability requirements for grade J55 tubing and couplings and grade K55 casing (used as tubing) and couplings.

IRP Hardenability tests shall be conducted on grade L80 type 1 tubing and couplings to meet the requirements of API 5CT for grade C90 type 1 and grade T95 type 1 tubing and couplings. The frequency of hardenability tests for grade L80 type 1 shall be per API 5CT for grade C90 type 1 and T95 type 1. For L-80, the manufacturer shall provide a minimum of 90% as-quenched martensite per API 5CT for grade C90 type 1 and T95 type 1.

Hardenability testing of grade C90 type 1 and T95 type 1 shall meet the requirements of API 5CT. The manufacturer shall provide a minimum of 90% as-quenched martensite per API 5CT for grade C90 type 1 and T95 type 1.
2.4.3.7 Hardness Testing

The following hardness restrictions shall be followed:

Tubing and coupling manufacturing specifications should stipulate that through thickness hardness testing be performed on the final product to confirm that these restrictions are met. Testing shall be performed in accordance with API 5CT. A hardness value is the average of three hardness readings or impressions per the API 5CT definition. The following table provides the requirements for hardness testing for non-upset tubing:

Table 2.4.3 Hardness Testing Requirements – Non-upset Tubing

<table>
<thead>
<tr>
<th>Hardness/Frequency</th>
<th>J55/K55</th>
<th>L80 type 1</th>
<th>C90 type 1</th>
<th>T95 type 1</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reading (max)</td>
<td>22.0 HRC</td>
<td>23.0 HRC</td>
<td>25.4 HRC</td>
<td>25.4 HRC</td>
</tr>
<tr>
<td>Value (min)</td>
<td>82.0 HRB</td>
<td>93.0 HRB</td>
<td>18.0 HRC</td>
<td>19.0 HRC</td>
</tr>
<tr>
<td>Value (max)</td>
<td>22.0 HRC</td>
<td>22.0 HRC</td>
<td>25.0 HRC</td>
<td>25.0 HRC</td>
</tr>
<tr>
<td>Frequency – tubing (one quadrant)</td>
<td>On every tensile test sample</td>
<td>On every tensile test sample</td>
<td>Per API 5CT for Group 2</td>
<td>Per API 5CT for Group 2</td>
</tr>
<tr>
<td>Frequency – coupling stock (four quadrants)</td>
<td>On every tensile test sample</td>
<td>On every tensile test sample</td>
<td>Group 2</td>
<td>Per API 5CT for Group 2</td>
</tr>
</tbody>
</table>

Hardness variation for all the above grades shall be per API 5CT for grades C90 type 1 and T95 type 1.

NOTE: Minimum hardness values are suggested to avoid galling damage which may occur when making/breaking connections during running into and out of wells.

For upset tubing, three samples shall be tested. One sample shall be taken from the pipe body, one sample shall be taken from the transition region, and the third sample shall be taken from the upset. All three samples shall be removed from the tubing after all heat treatment has been completed. The frequency for J55/K55 and L80 type 1 shall be once per heat or lot, whichever is more frequent. The frequency for Grade C90 type 1 and Grade T95 type 1 shall be per API 5CT.

2.4.3.8 Grain Size Determination

There are no grain size requirements for grade J55 tubing and couplings or for grade K55 casing and couplings used as tubing.
Grain size determinations shall be conducted on grade L80 type 1 tubing and couplings to meet the requirements of API 5CT for grade C90 type 1 and grade T95 type 1 tubing and couplings. The frequency and method of grain size determinations shall be per API 5CT. The prior austenite grain size of grades L80 type 1, C90 type 1 and T95 type 1 tubing and couplings shall be 7 or finer.

2.4.3.9 Hydrostatic Testing

Every tube shall be hydro-tested to 80% of the Specified Minimum Yield Strength (SMYS) to a maximum of 69 MPa.

2.4.3.10 Sulfide Stress Crack Testing

2.4.3.10.1 Introduction

Environmental embrittlement testing shall be done on a per heat per pipe size per heat treat lot basis. Alternatively, for grades J55, K55 (used as tubing) and L80, the manufacturer or user shall provide or develop data which demonstrate that material of the same grade, manufactured by the same process, has adequate resistance to environmental embrittlement per the test method and related acceptance criteria requirements of this IRP.

Four static-loaded sulfide stress cracking (SSC) test methods have been standardized by NACE International in Standard Test Method TM0177-964, “Laboratory Testing of Metals for Resistance to Specific Forms of Environmental Cracking in H₂S Environments”.

The four test methods are:


Two test solutions (A and B) may be used with methods A, C and D. Test method B has its own unique solution. Test solution A is the original ”NACE” environment. It 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 H₂S. SSC testing of tubing and couplings for
critical sour gas well service using methods A, C and D shall be performed in solution A.

NACE has not standardized a test method for Stress-Oriented Hydrogen-Induced Cracking (SOHIC) in tubular goods. However, both methods A and C are capable of determining the susceptibility of tubular goods to SOHIC. SOHIC is of particular concern in normalized and tempered materials, (i.e., seamless and electric resistance-welded J55/K55). SOHIC is less of a concern in materials given a quench and temper heat treatment. The purchaser/user shall determine whether testing of electric resistance-welded L80 type 1 for resistance to SOHIC is necessary.

Tubing will be subjected to both longitudinal and circumferential (hoop) stresses. The most commonly used SSC test method (NACE method A) applies stress in the longitudinal direction. The material properties in the longitudinal direction might not be representative of those in the circumferential direction. Both NACE methods C and D simulate the hoop stress in tubing. The method C specimen is ideal for testing the weld area of electric resistance-welded grade J55 tubing (or grade K55 casing used as tubing) for resistance to SOHIC. The method D specimen test technique is becoming more frequently used for the qualification of higher strength tubing and couplings for critical sour service. This test technique is not suitable for testing grade J55 tubing (or grade K55 casing used as tubing) because of the difficulty in initiating sulfide stress crack growth in this low strength material.

2.4.3.10.2 Pre-Qualification Manufacturers

The following protocol shall be used for the pre-qualification of manufacturers of tubing and couplings intended for use in critical sour gas wells:

- The manufacturer shall provide to the purchaser/user sufficient and persuasive SSC test data to satisfy the purchaser/user, that materials with adequate resistance can be routinely and consistently provided. Alternatively, the purchaser/user may develop these data.

- The SSC test data may either be relevant archival SSC test data, or may be obtained by successfully completing an appropriate laboratory SSC test program.

The following SSC test program is recommended for the pre-qualification of the manufacturer(s) of tubing and couplings intended for use in critical sour gas wells:
General requirements:

1. At least three different heats of tubing and three different heats of coupling stock (or individual couplings) shall be/ shall have been tested to confirm adequate SSC resistance, per the requirements of NACE International document MR0175, latest edition.5

2. The samples of tubing and couplings tested shall have been produced by exactly the same manufacturing route as will be used for the materials purchased for the critical sour gas well. In particular, the chemical compositions and heat treatment procedures shall be identical (within manufacturing tolerances).

3. The samples of tubing and couplings tested shall have diameters and wall thickness comparable with those that will be used in the critical sour gas well. The wall thickness of at least two of the three samples shall not be less than that of the tubing or couplings to be used in the critical sour gas well.

4. It is the responsibility of the purchaser/user to qualify the SSC test laboratory, (i.e., to confirm that they are capable of performing the SSC test method(s) correctly).

5. Specimens shall be taken from material as close as possible to the internal surface of the tubing or coupling.

6. Two samples shall be taken from upset tubing. One sample shall be taken from the pipe body and the other sample shall be taken from the upset.

Seamless J55 tubing and couplings (or K55 casing and couplings used as tubing): Testing shall be conducted in accordance with TM0177-96 methods A and C in the solution A environment.

Method A: Standard size specimens shall be used if wall thickness permits. At least three specimens of each sample shall be tested to confirm the threshold stress. Pass criteria are no failures and no visual observation of surface cracks per TM0177-96. Metallography shall be conducted to determine whether cracks on the gauge length are environmentally-induced. The acceptance criteria shall be threshold stresses of 80 % specified minimum yield strength (SMYS) minimum for standard size specimens and 72 % SMYS minimum for subsize specimens.
Method C: At least three specimens of each sample shall be tested to confirm the threshold stress. Pass criteria are no failures and no visual observation of surface cracks per TM0177-96. Metallography shall be conducted to determine whether cracks on the gauge length are environmentally-induced. The acceptance criterion shall be a threshold stress of 80% SMYS minimum.

Electric resistance-welded J55 tubing (or K55 casing used as tubing): The parent material shall be tested per the requirements and acceptance criteria for seamless J55 tubing and couplings. In addition, the weld area shall be tested in accordance with TM0177-96 method C in the solution A environment. The weld shall be located at the apex of the specimen. At least three specimens of each sample shall be tested to confirm the threshold stress. Mill scale on the internal and external pipe surfaces shall be removed by machining. Pass criteria are no failures and no visual observation of surface cracks per TM0177-96. Metallography shall be conducted to determine whether cracks on the specimen surface are environmentally-induced. The acceptance criterion shall be a threshold stress of 80% SMYS minimum.

L80 type 1, C90 type 1 and T95 type 1 tubing and couplings: Testing shall be conducted in accordance with TM0177-96 method A, plus either method C or method D, all in the solution A environment. Method D shall always be used unless the tubing diameter and wall thickness are such that testing using subsize (B = 4.76 mm) specimens is not possible. Only under these circumstances shall the method C test be employed.

Method A: Standard size specimens shall be used if wall thickness permits. At least three specimens of each sample shall be tested to confirm the threshold stress. Pass criteria are no failures and no visual observation of surface cracks per TM0177-96. Metallography shall be conducted to determine whether cracks on the gauge length are environmentally-induced. The acceptance criteria shall be threshold stresses of 90% SMYS minimum for standard size specimens and 81% SMYS minimum for subsize specimens.

Method C: At least three specimens of each sample shall be tested to confirm the threshold stress. Mill scale on the internal and external pipe surfaces shall be removed by machining. Pass criteria are no failures and no visual observation of surface cracks per TM0177-96. Metallography shall be conducted to determine whether cracks on the specimen apex are environmentally-induced. The acceptance criterion shall be a threshold stress of 90% SMYS minimum.
Method D: Standard size specimens shall be used if wall thickness permits. Sufficient specimens of each sample shall be tested to provide a minimum of three valid test results. Specimens of L80 type 1 and C90 type 1 shall be fatigue pre-cracked. Specimens of T95 type 1 need not be fatigue pre-cracked. After sufficient crack growth has occurred during fatigue pre-cracking, the peak load shall be reduced by 35%, and fatigue pre-cracking shall continue for a further 20,000 cycles to sharpen the crack tip and avoid plastic deformation of material immediately ahead of the crack. Specimen side arm displacements shall be in the middle of the ranges for each grade specified in TM0177-96. Both parent material and weld area material of electric resistance-welded L80 type 1 tubing shall be tested. The 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 shall be as follows for all grades and for both parent and weld area material:

1. Standard size (B = 9.53 mm) specimens: An average $K_{1SSC}$ (Stress Intensity Factor for Sulfide Stress Cracking) value of 33.0 MPa$\sqrt{m}$ minimum, and a single specimen $K_{1SSC}$ value of 29.7 MPa$\sqrt{m}$ minimum.

2. Subsize specimens: Subsize specimens shall be used if tubing or coupling size prevents the use of standard size specimens. The manufacturer and the purchaser/user shall agree upon the acceptance criteria for subsize specimens. It is common practice to decrease the average and single specimen acceptance criteria for standard size specimens by 15% for subsize (B = 6.35 mm) specimens, and by 20% for subsize (B = 4.76 mm) specimens. However, the validity of doing this has not yet been substantiated through the application of fracture mechanics theory.

2.4.3.10.3 Quality Assurance Testing

IRP The following quality assurance SSC testing shall be done for the purchase of sour service-rated tubing and couplings for critical sour gas wells:

- Test procedures and acceptance criteria shall meet the requirements specified above for the pre-qualification of manufacturers of tubing and couplings for critical sour gas wells.
- Test frequency for all grades shall be one sample per heat per tubing or coupling size per heat treat lot. Two test samples shall be taken...
from upset tubing; one from the pipe body and the other from the upset.

- Test samples shall be obtained from material with the highest yield strength, as determined by the mandatory mechanical properties testing. In the event that one or more samples have similar yield strength, the sample with the highest hardness values shall be selected for testing.

- When J55 (or K55 casing used as tubing) and L80 type 1 tubing and couplings are specified, the purchaser/user may, at their discretion, decide that quality assurance SSC testing need not be conducted if the manufacturer has been pre-qualified.

- When C90 type 1 or T95 type 1 tubing and couplings are specified, the purchaser/user shall require that quality assurance SSC testing be conducted to confirm that the supplied materials have adequate SSC resistance, per the requirements of API 5CT and this IRP.

2.4.3.11 Hydrogen-Induced Crack Testing

2.4.3.11.1 Introduction

Hydrogen-Induced Cracking (HIC) tests shall be done for grades J55 and K55 (used as tubing). HIC testing shall be done on a per heat per pipe size per heat treat lot basis. Alternatively, for seamless grades J55 and K55 (used as tubing), the manufacturer or user shall provide or develop data which demonstrates that material of the same grade, manufactured by the same process, has adequate resistance to HIC per the test method and acceptance criteria requirements of this IRP.

Quality assurance HIC tests should always be conducted on electric resistance-welded pipes of J55 and K55 (used as tubing).

HIC tests and pre-qualification of manufacturers are not necessary for grades L80 type 1 (seamless or electric resistance-welded), C90 type 1, and T95 type 1 tubing and couplings.

2.4.3.11.2 Pre-Qualification of Manufacturers

The following protocol shall be done for the pre-qualification of manufacturers of grades J55 and K55 tubing and couplings intended for use in critical sour gas wells:
• The manufacturer shall provide to the purchaser/user sufficient and persuasive HIC test data to satisfy the purchaser/user, that materials with adequate resistance can be routinely and consistently provided. Alternatively, the purchaser/user may develop these data.

• The HIC test data may either be relevant archival HIC test data, or may be obtained by successfully completing an appropriate laboratory HIC test program.

The following HIC test program is recommended for the pre-qualification of the manufacturer(s) of grades J55 and K55 tubing and couplings intended for use in critical sour gas wells.

General requirements include:

1. At least three different heats of tubing and three different heats of coupling stock (or individual couplings) shall be/ shall have been tested to confirm adequate HIC resistance.

2. The samples of tubing and couplings tested shall have been produced by exactly the same manufacturing route as will be used for the materials purchased for the critical sour gas well. In particular, the chemical compositions and heat treatment procedures (if any) shall be identical (within manufacturing tolerances).

3. The samples of tubing and couplings tested shall have diameters and wall thickness comparable with those that will be used in the critical sour gas well.

4. HIC tests shall be conducted in accordance with NACE International Standard Test Method TM0284-96, “Evaluation of Pipeline and Pressure Vessel Steels for Resistance to Hydrogen-Induced Cracking”. Test solution A shall be used. Tubing and couplings shall be tested in the same manner as the comparable linepipe (seamless or electric resistance-welded).

5. It is mandatory to continuously bubble H$_2$S through the test solution for the duration of the test (after the initial saturation period). The same rate as that specified in TM0177-96 for method A shall be used.

6. It is mandatory to lightly etch the metallographic cross-sections of the tested specimens before examination for the presence of HIC damage.
7. It is the responsibility of the purchaser/user to qualify the HIC test laboratory, i.e., to confirm that they are capable of performing the HIC test method correctly.

8. Both the pipe body and upset area of upset tubing shall be tested.

**Acceptance criteria:**

The 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. The sample average CLR and CTR are the average CLRs and CTRs of all nine cross-sections (three cross-sections of each of three specimens). In addition, no single cross-section shall have a CLR which exceeds 25 %, or a CTR which exceeds 10 %.

2.4.3.11.3 Quality Assurance Testing

**IRP** The following quality assurance HIC testing protocol shall be done for the purchase of grades J55 and K55 tubing and couplings for critical sour gas wells:

- Test procedures and acceptance criteria shall meet the requirements specified above for the pre-qualification of manufacturers of grades J55 and K55 tubing and couplings for critical sour gas wells.

- Test frequency for both grades shall be one sample per heat per tubing or coupling size per heat treat lot. Two test samples shall be taken from upset tubing; one from the pipe body and the other from the upset.

- When seamless grades J55 or K55 tubing and couplings are specified, the purchaser/user may, at their discretion, decide that quality assurance HIC testing need not be conducted if the manufacturer has been pre-qualified.

- Quality assurance HIC testing shall be mandatory for electric resistance-welded grades J55 and K55 tubing and couplings.
2.4.3.12 Inspection

The following inspections shall be done for the detection of defects in tubing and coupling stock per (API 5CT):

Table 2.4.4 Supplementary Inspection Requirements

<table>
<thead>
<tr>
<th></th>
<th>J55/K55</th>
<th>L80 type 1</th>
<th>C90 type 1</th>
<th>T95 type 1</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tubing</td>
<td>SR1 is acceptable SR2 is recommended</td>
<td>SR2</td>
<td>SR2</td>
<td>SR2</td>
</tr>
<tr>
<td>Coupling stock</td>
<td>SR14</td>
<td>SR14</td>
<td>SR14</td>
<td>SR14</td>
</tr>
</tbody>
</table>

API 5CT uses SR to mean Supplementary Requirements.

Special end area (SEA) inspection is required on every pipe length unless the manufacturer crops the pipe ends not covered by the automated pipe body inspection equipment. Visual and magnetic particle inspection (MPI) of both the internal and external surfaces of the pipe end for the presence of transverse and longitudinal defects shall be conducted. The SEA inspection shall overlap the automated pipe body inspection by a minimum of 50 mm.

Exposed threads shall be visually inspected for damage. Consult API RP 5A57 section 4.4 for details of the required inspection.

2.4.3.13 Marking

All pipe and couplings manufactured to meet or exceed this specification shall be stenciled to permit future traceability.

2.4.3.14 Guidelines for Non-Compliant and/or Used Tubing

All tubing for use in critical sour wells is classified as follows:
1. Used Tubing originally made in compliance with this IRP.
2. Used Tubing 1, not originally made in compliance with this IRP.
3. New Tubing2, not made to this IRP.
4. New Tubing3, made to this IRP.

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1 Tubing that has previously been run in a well
2 Tubing that has never been run in a well
3 Tubing that has never been run in a well
The following sections outline extra testing and documentation requirements for tubing in categories one, two and three above to qualify it for use in critical sour service.

### 2.4.3.14.1 Used IRP Compliant Testing

**IRP** Used pipe originally manufactured in compliance with this IRP is acceptable provided it passes the following inspection:

- Full length API drift.
- Full body inspection for longitudinal and transverse defects, ID and OD.
- Special end area (SEA) inspection on one joint in 20. (Reference Section 2.4.4.5).
- Pipe should be marked to allow future traceability back to this inspection. Pipe that was originally manufactured to meet or exceed this IRP should also be re-stenciled with an appropriate designation upon recovery from the well to provide traceability.

### 2.4.3.14.2 Used Non-IRP Compliant Tubing

**IRP** Used tubing not originally made in compliance with this IRP shall be treated in the same manner as new, non-IRP compliant tubing, see section 2.4.3.14.3. In addition, it shall receive full length drift testing. Straightening of tubing shall not be permitted.

Inspection is not required in workover applications, where the pipe is being pulled and re-run in the same well.

### 2.4.3.14.3 New Non-IRP Compliant Tubing

With regard to the recommendations in Section 2.4.3.2 (Implementation), this section 2.4.3.14.3 is only intended to cover new pipe manufactured and purchased before the publishing date of this IRP (i.e. existing inventory).

**IRP** New tubing not originally made in compliance with this specification is acceptable provided it passes the following inspection and testing requirements:

- The tubing and couplings shall be tested to confirm resistance to SSC, HIC and SOHIC per the requirements in this IRP (2.4.3.10.3 - quality assurance SSC testing and 2.4.3.11.3 - quality assurance...
Completing and Servicing Critical Sour Wells

HIC testing). This requirement applies to J55/K55 and L80 type 1 as well as to C90 type 1 and T95 type 1.

- Special End Area Inspection (SEA) shall be conducted on every joint (Reference Section 2.4.4.5).

- For grade J55, grade K55 (casing used as tubing), and grade L80 type 1, a random surface hardness test should be conducted on one pipe in fifty and on all couplings (unless mill hardness records are available). Hardness tests should be conducted on both pipe ends. Upset pipe should be tested on the pipe body and on the upset of both ends. Hardness readings greater than 22.0 HRC or hardness values less than 82.0 HRB shall be cause for rejection of the grade J55/K55 pipe or coupling, and for an increased inspection frequency of the pipe. Hardness readings greater than 23.0 HRC or hardness values less than 93.0 HRB shall be cause for rejection or prove-up of the grade L80 type 1 pipe or coupling, and for an increased inspection frequency of the remaining pipe. If any single hardness reading falls outside the requirements above, two additional readings shall be taken in the same area to prove-up the pipe or coupling. The average of all the readings shall fall within the specified hardness ranges for the pipe or coupling to be acceptable. The inspection frequency shall be increased to every pipe.

- Every joint used must be traceable back to mill certificates documenting tensile strength and chemistry at least.

- Use of used and new, non-compliant grade C90 type 1 and T95 type 1 tubing and couplings is not recommended.

- Pipe should be marked to allow future traceability back to this inspection. Re marking the pipe immediately upon recovery from the well is recommended to maintain traceability.

2.4.3.15 Documentation

Mill certification records indicating chemistry, mechanical and metallurgical (grain size, microstructure) properties, hardenability and hardness readings, and the results of sulfide stress cracking and hydrogen-induced cracking tests shall be maintained by the operator. Results of third party tests and inspections performed in accordance with Section 2.4.3.14 shall also be maintained by the operator.
### 2.4.4 Tubular Connections

**NOTE:** The following section covers carbon and low alloy steel tubing connections intended for use in critical sour service applications. It includes connection types, inspection and testing, running guidelines, storage, and documentation.

#### 2.4.4.1 Service Level Definitions and Connection Types

It is intended that the connection requirements and the associated inspection and handling increases as the severity of service increases.

##### 2.4.4.1.1 Light Service

**IRP** API EUE connections, Semi-premium connections\(^4\) and Premium connections\(^5\) are all acceptable for Light Service.

Light Service is meant for oil wells or low pressure gas wells that generally display the following characteristics:

- Differential pressures less than or equal to 21 MPa.
- Depths less than or equal to 3500 m.
- Non-deviated or mildly deviated wellpath (less than 20° angle from vertical, less than 5°/30m dogleg severity).
- Temperatures and fluids that do not effect the ability of the thread lubricant sealing with the EUE connection. Check thread lubricant manufacturer for specific data on the proposed thread lubricant.
- Non corrosive service.

##### 2.4.4.1.2 Moderate Service

**IRP** Only Semi-premium or Premium connections **shall** be used for Moderate Service.

Moderate Service is similar to Light Service, but with added complications such as:

- Temperatures and fluids that affect the ability of the thread lubricant sealing with the EUE connection.
- More deviated wells than described in Light Service.

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\(^4\) Semi-Premium connections have at least one additional feature beyond API threads (torque shoulder, resilient seals).

\(^5\) Premium connections have at least two additional features feature beyond API threads (alternate thread profiles, torque shoulder, metal-to-metal seals).
• Differential pressures greater than 21 MPa.

**NOTE:** The upper pressure limit of Semi-premium connections that utilize a resilient seal should consider the combination of internal tubing pressure and the pressure generated by the confined resilient seal.

### 2.4.4.13 Harsh Service

**IRP** Only Premium connections shall be used for Harsh Service.

• Harsh Service is meant for more complex wells that may include such complications as:
  • High differential pressure.
  • High temperatures.
  • Highly deviated wells.
  • Corrosive environment such that resilient seals are not effective or a more streamlined flowpath is desired in the coupling area.
  • Abrasive/erosive environment such that a more streamlined flowpath is desired in the coupling area.
  • Well Service work requiring stripping or snubbing.

### 2.4.4.2 Inspection and Testing Requirements for Light Service

All new and used tubing connectors should be inspected at mill or storage yard prior to wellsite shipment. See General Inspection Guidelines (2.4.4.5) for recommended mill/yard inspection requirements. The following on site minimum inspection requirements are recommended:

#### 2.4.4.2.1 Work String

After four or five trips or extensive milling operations it is recommended connectors be visually inspected for galled threads, swaged pin noses and/or belled boxes at a frequency of 1 joint per 20. This problem is more prevalent on API EUE connectors.

#### 2.4.4.2.2 Production Sting

Both pin and box threads should be washed clean, preferably with a mechanical power thread cleaner equipped with non-metallic bristles immediately prior to running.
IRP  Connectors shall be visually inspected for galled threads, swaged pin noses and/or belled boxes.

Use of a hardened, ground API thread profile gauge is recommended for locating stretched or damaged API 8-round threads. A frequency of one per twenty joints depending upon overall thread condition should be sufficient in most instances. If numerous joints are rejected by this method a more rigorous inspection frequency is warranted.

IRP  The tubing connections shall be pressure tested either individually or collectively over the entire tubing string. Pressure testing may be conducted with inert gas or a clean, low viscosity liquid.

When EUE workstrings are ultimately utilized as the final production string, special attention is required during make-up to monitor pin advancement into the coupling (see General Inspection Guidelines 2.4.4.5).

NOTE:  Multiple make and breaks to similar torque values will cause progressive pin advancement thereby increasing axial and box hoop tensile stresses. A torque shoulder feature is recommended to minimize this concern.

2.4.4.3  Inspection and Testing Requirements for Moderate and Harsh Service (Semi-premium and Premium Connections).

IRP  All new and used tubing connectors shall be inspected at mill or storage yard prior to wellsite shipment. See General Inspection Guidelines (2.4.4.5) for recommended mill/yard inspection requirements.

The following are minimum on-site inspection requirements:

2.4.4.3.1  Work Sting

IRP  Both pin and box threads shall be washed clean using a mechanical power thread cleaner, equipped with non-metallic bristles, and visually inspected on each trip. This is recommended due to galling propensity of metal-to-metal seals.

IRP  After extensive milling/drilling operations connectors shall be closely inspected prior to and after breakout for thread and/or metal to metal seal damages belled boxes or swaged pin noses. A steel straight edge may be used to aid visual inspection.
2.4.4.3.2 Production Sting

**IRP** Both pin and box threads shall be washed clean using a mechanical power thread cleaner equipped with non-metallic bristles immediately prior to running.

It is recommended that a qualified thread inspector\(^6\) be on-site prior to and during running of production string to assist in thread inspection.

**IRP** Each connector shall be visually inspected, prior to make-up, on the rig floor.

Special emphasis should be placed on metal-to-metal seal inspection particularly if the production string had been used as a work string.

**IRP** The tubing connections shall be pressure tested either individually or collectively over the entire tubing string. Pressure testing may be conducted with inert gas or a clean, low viscosity fluid.

**IRP** When workstrings are used as final production strings, the connection shall be visually monitored for excessive pin advancement during make-up.

**NOTE:** Even some premium connectors with torque shoulders are susceptible to this phenomenon when subjected to milling/drilling operations.

2.4.4.4 Conector Running Guidelines

The following sections present recommended thread lubricant, make-up and break-out guidelines. In general, the recommendations do not change with Service Level. However, extra care is warranted for Moderate and Harsh Service Levels.

2.4.4.4.1 Thread Lubricants

**IRP** Only approved API Modified thread lubricants or equivalent shall be used. This allows for the use of non-lead based lubricants provided they have been qualified for the intended service.

Thread lubricant, which is more than two years old, should not be used on production strings.

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\(^6\) Refers to a thread inspector who has passed written and operational exams involving inspection principles and procedures.
NOTE: The thread lubricant is the primary sealing mechanism for API EUE and some semi-premium connectors. Consequently, application should be consistent and thorough in an effort to achieve a leak proof connection.

After two years degradation of the solids carrier (grease base) may occur, typically resulting in uneven dispersion of damming solids. Consequently, sealing integrity may be reduced since the damming solids will not be uniformly distributed along thread roots and crests when applied. Oil bleed to surface of the lubricant in a container, may indicate grease degradation.

Thread lubricants are subject to degradation with increasing temperature and harsh fluid environments. Consultation with the connection and lubricant manufacturers is advised.

Thread compound should be applied uniformly covering all threaded and seal areas. Check with the connection manufacturer to see if pin only, or box only, or both pin and box lubrication is recommended.

Do not over apply thread compound. Note that cold weather thread compound may be advantageous for consistent application in the winter months.

2.4.4.4.2 Make-up/Break-out Guidelines
2.4.4.4.2.1 Make-up
• Ensure elevators are vertically aligned with the center of wellbore to mitigate misalignment problems. If there is sufficient room in the derrick a stabbing platform should be used.
• If the connector is incorrectly stabbed (i.e. if it is cross-threaded or if the pin nose hits the box face first) pick-up and visually check seal and threads for damage.
• Do not rock pipe to facilitate stabbing or make-up.
• All production string connections should be started by hand to minimize cross threading and thread damage. All premium connectors should also be started by hand.
• Connection should be made-up at manufacturer's recommended speed or maximum 20 RPM and kept constant during make-up. Tongs should hang level during make-up.
• Snub line should be as close to 90o from torque arm as possible.
• Power tongs and back-ups should be reasonably close together to prevent bending the connector.

• Connections should be made-up to manufacturer’s recommended torque. Thread plating, coating or thread lubricant type may have pronounced effects on applied torque. Consequently, the connection and lubricant manufacturers should be consulted for appropriate torque and friction factor values.

• For Premium connections, use a load cell with torque gauge in snub line to monitor torque. Do not rely on hydraulic pressure gauges. Ensure the load cell has been recently calibrated. In addition, a torque monitoring unit should be considered for use while making up work string and production string connectors for Moderate or Harsh Service Levels. The unit should have a torque alarm system as a minimum. A torque/turn/time unit is preferred for production strings.

2.4.4.4.2 Break-out
• Equal emphasis should be placed on connector break-out as is placed on make-up, especially semi-premium or premium connectors.

• Position break-out tongs close to the coupling. Hammering the coupling to break the joint is an injurious practice.

2.4.4.5 General Inspection Guidelines
The following inspection guidelines are applicable to all Service Levels:

• Only qualified thread inspectors should be utilized at the mill or storage yard. Inspectors are qualified by passing written exams involving inspection principles and procedures. An operational exam is also a prerequisite. These requirements are also applicable to proprietary thread inspectors. Additionally, they should have one-year’s field experience with the particular connector thread type being utilized.

• When proprietary (i.e. Non API) connectors are being threaded, it is recommended that a third party inspector or the operator’s qualified representative be employed to verify that the manufacturer’s specified inspection procedures and frequencies are adhered to.

• Due to corrosion potential of stored tubing, an evaluation of the threaded connector condition (including seal areas) should be conducted on production tubing prior to wellsite shipment. A visual thread inspection as per API RP 5A57 Section 2.6 is recommended. The recommended maximum duration between last inspection and utilization of tubing is 12 months, depending upon thread protector type and thread lubricant’s corrosion resistant properties.
In addition to standard API inspection practices for used tubing connections a "Special End Area Inspection" (API RP 5A5\textsuperscript{7} Section 4.4) utilizing wet Magnetic Particle Inspection (MPI) should be conducted in the storage yard prior to use. An inspection frequency of one joint per twenty for IRP compliant tubing is recommended. If numerous connectors are rejected using this method, a more rigorous frequency should be employed.

For non-IRP compliant tubing, special and area inspection should be conducted on every joint.

Supplemental coupling inspection SR 14 (wet MPI) per API 5CT\textsuperscript{3} should be conducted at the mill.

API EUE work strings and used tubing intended for production string applications should be randomly checked for pin advancement in storage yard prior to wellsite shipment. For box ends, measure the distance from coupling face to pin nose. The minimum distance (x) before joint should be laid down or recut is:

\[
x = \frac{N_L + 1P}{2}
\]

Where:  
- \(N_L\) = length of coupling
- \(1P\) = 1 pitch
- \(x\) = minimum distance to pin nose from coupling face

(See API RP 5A5\textsuperscript{7}, STD 5B\textsuperscript{8} or STD 5CT\textsuperscript{3} for dimensions).

This inspection should also be performed on-site as required in Section 2.4.4.2.2.

Prior to make-up, the L4 distance (API RP 5A57 or STD 5B8) should be marked on random API pin ends with paint or chalk. The line should be approximately 10 mm (0.375") in width. If the line is completely covered by coupling when recommended torque is reached, the joint should be removed. Excessive occurrence indicates worn connectors and the couplings or string should be replaced.

2.4.4.6 Documentation

The results of the aforementioned inspections in section 2.4.4.5 should be maintained by the Operator and include the following:

- Inspection company
- Date of inspection
- Inspection performance
The inspection company should stencil an identifier on the tube, which permits traceability back to the inspection performed.

### 2.4.5 Quality Assurance

Proper consideration of the matter of quality assurance for tubular goods is essential in ensuring the installation and operation of a competent tubing string. The matter of quality assurance has been dealt with from an overall perspective in IRP 2.10.

### 2.4.6 Running and Handling

#### 2.4.6.1 General

**IRP**

*API Recommended Practice 5C1<sup>9</sup> shall be referred to for running and handling recommendations.*

**NOTE:** Adherence to proper running and handling procedures can reduce the risk of a pipe or connector failure downhole. *API RP 5C1<sup>9</sup> is a thorough and practical guide for the running and handling of oilfield tubular goods. Many of the notes in this section are repeated from API RP 5C1<sup>9</sup>.*

#### 2.4.6.2 Transportation and Handling

The operator should ensure that tubing for critical sour service is transported and handled using techniques that minimize both connection and pipe body damage.

The following specific handling guidelines are suggested:

- Tubing should have thread protectors on both ends.

- Tubing should be strapped down with nylon straps or chains with rubber protection underneath. Straps or chains should be secured only where tubing is on stripping.

- Tubing is to be unloaded on location by picker or tubing ramps onto pipe racks. A spreader-bar with a choker-sling at each end is recommended by *API RP 5C1<sup>9</sup>*. When using ramps, lower one or two joints at a time, and avoid contact that may damage threads.

#### 2.4.6.3 Wellsite Handling Equipment and Procedures

**IRP**

*Do not place back-up tongs on the box for wells with Moderate and Harsh Service Levels because the tong marks create stress risers in this area that is already has a high hoop stress. Do not place back-up tongs on the upset fade away of the connection.*
Furthermore, the operator should ensure that the equipment and techniques used to run the tubing do not cause other pipe body or connection damage that could cause & failure in service. Although it is not possible to eliminate all pipe body damage, the practical goal is to avoid deep slip marks that cause stress concentrations that can initiate failure, and to avoid concentrated loadings that can deform the pipe body. The following guidelines are highlighted:

- Drift tubing prior to running with proper size drift. If tubing is coated, use wooden or plastic drift to the coating manufacturer's specifications. An API drift is usually impractical for wellsite applications due to its length and weight.

- Check elevators for vertical alignment over the hole. Level the rig if necessary.

- Elevators should be double latched, in good repair, with links of equal length. Slip type elevators are recommended.

- Spider slips, which will not crush the tubing, should be used. Ensure that the slips are sharp and that all segments are working together.

- Tubing tongs, which will not crush the tubing, should be used on the body of the tubing and should fit properly to avoid unnecessary cutting of the pipe wall. Tong dies should fit properly to avoid unnecessary cutting of the pipe wall. Tong dies should fit properly and conform to the curvature of the tubing. The use of pipe wrenches is not recommended.

- Use full contact tubing tongs for back-up with 330° die coverage of the tubular.

- Ensure back-up tong is as level as possible.

- Use back-up tongs until string weight permits no movement of the string in the table slips during make-up.

- Bring the joint being run to a complete stop prior to setting the slips.

- When running upset tubing, ensure the strike plate on slip type elevator hits the fade away and sets the slips.

- Lift the tubing slowly to disengage floor slips to prevent swinging of the blocks or damage to pipe or couplings.
2.4.7 CORROSION MONITORING AND INSPECTION

2.4.7.1 Definitions

Monitoring and inspection procedures are normally necessary to confirm that process parameters are within design limits. Monitoring is the ongoing monitoring of the corrosion process and measures taken to control it. Inspection is the provision of mechanical integrity assurance. Inspection provides data points against which corrosion monitoring is often related or quantified.

2.4.7.2 Monitoring Methods

There are numerous methods available to monitor the effect of corrosion on tubular goods. Since each method has its own merits and limitations, relying on one single method can lead to erroneous evaluation of the tubing condition.

These methods can generally be divided into two categories:

a) intrusive measurements which require production to stop, and

b) non-intrusive measurements which can be done without interrupting flow.

A variety of monitoring techniques are included in Appendix A and B. The most common are caliper logs, inspection logs, coupons, electronic monitoring methods, iron counts, and visual inspection. The most effective is a complete visual inspection, with selective destructive testing of the tube throughout the string. Unfortunately, this can only be accomplished during a workover. The techniques should be selected on an individual well basis, depending on operating condition, previous experience, etc. Consider field results from the offset wells to assist evaluating specific wells.

2.4.7.3 Monitoring Schedule

On new completions, the extent of tubing corrosion should be monitored within six months of start up, unless field history dictates a lesser frequency is justified.

An ongoing tubing corrosion-monitoring program should be developed and implemented on all critical sour wells on production. Again, field history may dictate that this is not required, however, process analyses should be performed to ensure that the production characteristics are similar to the rest of the field.

**NOTE:** Most corrosion related tubing failures occur due to localized corrosion, rather than general metal loss corrosion. In some environments, severe pitting can occur rapidly. The six-month schedule suggested for a new well should identify whether a problem exists. The method selected is at the operator’s discretion.
The frequency of the monitoring schedule should be dependent on the methods selected, how aggressive the environment is (e.g., partial pressures of CO$_2$ and H$_2$S, brine content, temperature, presence of hydrocarbon condensate, elemental sulfur and sulfur solvents such as DMDS or DADS, the inhibition program, tubular condition, etc.). The initial monitoring frequency should not exceed two years for wells that exhibit corrosion potential. Field experience and the success of mitigation programs may dictate that a lesser or greater frequency is more appropriate. If production characteristics change, the inspection frequency should be re-evaluated.

Consider running a tubing inspection log during the initial production test and every five years thereafter. If corrosion is apparent, the frequency should be increased.

If a caliper log is run, ensure the tubing is internally inhibited immediately after logging. The caliper fingers may disrupt the natural (i.e., iron sulfide scale) or routine inhibition of the tubing surface and accelerate local corrosion.

### 2.4.7.4 Design Limits

It is recommended that the operator make a best effort to estimate the pipe condition from the monitoring results. The physical properties should be recalculated to ensure that adequate mechanical strength remains.

Some monitoring procedures have the potential to directly measure pipe thickness. However, scale and other deposits can affect the results of the measurements.

Since most of the monitoring methods only identify potential corrosion problems, some correlation between the monitoring results and pipe conditions should be devised. This correlation will be dependent on various factors (monitoring method, mitigation program, fluid rates and composition, pipe grade, failure history, time, etc.).
2.4.7.5 Tubular Corrosion Mitigation

IRP  Consistent with this objective the operator shall attempt to mitigate tubular corrosion to reduce the frequency of workovers.

NOTE: Several methods are listed below:

- corrosion inhibition: batch and/or continuous
- special tubular grades
- tubular coatings
- corrosion allowance

2.4.7.6 Records

Records should be kept on an individual well basis and include at least the following:

- Fluid analyses, producing rates and temperatures, gas dew point, location of free water production in string.
- Tubular string details, failure history, workover details (if a workover is conducted, include the internal and external visual inspection results).
- Monitoring methods and results, corrosion mitigation program and details.

These records should be updated regularly and at any time the tubing is pulled from the well.

NOTE: Accurate records will assist the operator in assessing tubing condition and the effectiveness of the corrosion mitigation program.

2.4.7.7 Annular Corrosion Mitigation

IRP  To help prevent annular corrosion, the annular fluid shall be inhibited with a compatible chemical package designed to remain permanently in suspension.

This chemical package should contain: a filming corrosion inhibitor, oxygen scavenger, a neutralizing agent, and a “disinfectant” which is effective at destroying organic life (not necessarily a biocide).

NOTE: Sweet crude, diesel, stabilized condensate, or an inhibited fresh water or brine are acceptable annular fluids. Refer to IRP 2.11 for elastomer compatibility information.
If a workover is performed, the tubing should be visually inspected to check the effectiveness of the inhibitor. If external pitting is apparent, consider running a casing inspection log across the interval. This information should be recorded and kept in the well’s corrosion file.

2.4.7.8 External Casing Corrosion Mitigation

The need for cathodic protection of the production casing should be evaluated on a field basis. If required, a properly designed cathodic protection system should be installed within one year of rig release.

**NOTE**: The entire cathodic protection system should be properly operated and maintained. The cathodic protection units should be kept in continuous operation and rectifier DC outputs measured and recorded monthly. This information should be placed in a permanent well file and reviewed annually.
## APPENDIX A. DIRECT CORROSION MONITORING METHODS

<table>
<thead>
<tr>
<th>Technique</th>
<th>Principle</th>
<th>Advantages</th>
<th>Disadvantages</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mechanical Tubing Caliper</td>
<td>Measure tubing ID and change with time</td>
<td>(1), (2)</td>
<td>- Scale build-up will affect results</td>
</tr>
<tr>
<td>Survey</td>
<td></td>
<td>- tubing OD’s &gt; 60.3 mm</td>
<td>- Cost</td>
</tr>
<tr>
<td>Ultrasonic/Magnetic</td>
<td>Measure tubing material loss</td>
<td>(1), (2)</td>
<td>- Scale build-up will affect results</td>
</tr>
<tr>
<td>Induction Log</td>
<td></td>
<td></td>
<td>- Cost</td>
</tr>
<tr>
<td>Visual Inspection</td>
<td>Direct visual inspection of tubing when pulled</td>
<td>(1), (2)</td>
<td>- Generally not practical to pull tubing for inspection only</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>- Abrasive cleaning often necessary</td>
</tr>
<tr>
<td>Radioactive Joints</td>
<td>Place joint(s) in corrosion susceptible area(s)</td>
<td>(1)</td>
<td>- Does not distinguish general corrosion from pitting</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>- Cannot directly determine corrosion rate</td>
</tr>
<tr>
<td>Sacrificial Pup Joints</td>
<td>Check produced fluids for radioactive solids</td>
<td>(1), (2)</td>
<td>- Once tubing run, cannot change position</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>- May never pull tubing</td>
</tr>
</tbody>
</table>

(1) Can identify regions in tubing where corrosion exists.

(2) Can identify pitting corrosion.
## APPENDIX B. INDIRECT CORROSION MONITORING METHODS

<table>
<thead>
<tr>
<th>Technique</th>
<th>Principle</th>
<th>Advantages</th>
<th>Disadvantages</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wellhead and Slipstream coupons</td>
<td>Weight loss</td>
<td>- Easy to install</td>
<td>- Requires time to work</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Measures corrosion rates</td>
<td>- Not reliable for pitting corrosion</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Visual inspection can identify pitting</td>
<td></td>
</tr>
<tr>
<td>Electronic Monitoring</td>
<td>Change in resistance as probe corrodes</td>
<td>- Readings are much quicker than coupons</td>
<td>- Sensitive to deposits on probe</td>
</tr>
<tr>
<td>- Electrical Resistance Probe</td>
<td></td>
<td>- Averages corrosion</td>
<td>- Not reliable for pitting corrosion</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Can be effective in optimizing corrosion mitigation programs</td>
<td></td>
</tr>
<tr>
<td>Electronic Monitoring</td>
<td>Measures solution corrosivity</td>
<td>- Subject to fouling</td>
<td></td>
</tr>
<tr>
<td>- Linear Polarization</td>
<td></td>
<td>- Requires reasonable solution conductivity</td>
<td></td>
</tr>
<tr>
<td>Electronic Monitoring</td>
<td>Sensitive monitoring on probe elements</td>
<td>- Does not measure actual corrosion rates</td>
<td></td>
</tr>
<tr>
<td>- Electrochemical Noise</td>
<td></td>
<td>- Relatively expensive</td>
<td></td>
</tr>
<tr>
<td>Subsurface coupons</td>
<td>Set in tubing</td>
<td>- Measure corrosion rates</td>
<td>- Change flow regime</td>
</tr>
<tr>
<td></td>
<td>- Weight loss</td>
<td>- Visual inspection can identify pitting</td>
<td>- May not be representative of actual corrosion</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>- Difficult to retrieve</td>
</tr>
<tr>
<td>Downhole scale samples</td>
<td>Scrape off scale inside tubing</td>
<td>- Can check various sections</td>
<td>- Corrosion process may not be detrimental to tubing</td>
</tr>
<tr>
<td></td>
<td>- identify deposit chemistry</td>
<td>- Presence of Fe-based corrosion product may indicate some type of corrosion process</td>
<td></td>
</tr>
</tbody>
</table>

NOTE: Surface measurements are not always representative of corrosion processes or conditions downhole.
List of References


2.5 Fluids and Circulating System

2.5.1 Scope

2.5.1.1
IRP 2.5 was prepared by the Fluids and Circulating System Subcommittee for the Blowout Prevention Well Service Committee (BPWSC) and revised by the ARP Vol. 2 Revision Committee to address the minimum acceptable standards for equipment and completion/workover fluids for well control and fluid handling on critical sour wells when the critical zone is open. If the zone is mechanically plugged off, then other fluids with less density than the kill fluid may be used once the Blowout Preventers are installed.

2.5.1.2
Throughout this section IRPs are highlighted in bold type and the word “shall” or “must” is used. Additional best practices are not highlighted and contain the words “should” or “recommended”.

2.5.2 Surface Equipment

2.5.2.1 Pressure Rating Of Surface Equipment
IRP Circulating pumps, manifolds, discharge lines, and return lines must have a working pressure equal to or greater than the working pressure of the wellhead top section (Christmas tree) or 1.2 times the shut-in tubing pressure, whichever is the lesser. Design working pressure limits of equipment must be considered for equipment selection to assure that it is capable of safe operation at the anticipated pressures.

2.5.2.2 Back-up Pumps
IRP Where a hard shut in cannot be conducted during pumping operations, a back up pump with manifold is required on location to maintain control of the well since a pump failure could lead to an uncontrolled flow.

For wells that can be shut in, contingency plans must be in place for a back-up pump with manifold to be brought to location should the rig pump fail.
2.5.2.3 Rig Pump

IRP The rig pump must have a discharge rate of sufficient capability to control the well.

For winter operation, pump and manifold must be adequately heated to prevent freezing.

NOTE: The pump sizing will be site specific and dependent on the casing size, tubing size and well condition.

2.5.2.4 Rig Tank

IRP The rig tank must provide for accurate fluid gauging and include the primary mixing system. For winter operation, tanks must be adequately heated to prevent freezing. Rig tanks equipped with properly maintained steam coils will prevent freezing and steam contamination of fluid.

2.5.2.5 Shale Shaker or Rig Tank Trough

Shale shakers or rig tank troughs cannot be used when sour effluent is being circulated from the well.

NOTE: Production test equipment does not have the capability of handling large size solids. Closed pressure vessels are available within the industry to handle the sour gas, fluids and large sized cuttings. These pressurized vessels are capable of handling large sized cuttings and diverting sour gas to flare or to a vapour recovery system.  

2.5.2.6 Fluid-Gas Separators

IRP Fluid-gas separators cannot be used on open rig tanks, as sour effluent cannot be emitted to atmosphere.

NOTE: Sour effluent must be directed through temporarily installed separation equipment to closed storage vessels equipped with vapour recovery systems or directed to an existing flowline capable of handling sour production fluids.

2.5.2.7 Premix Tank

NOTE: The first factor in determining the need for supplemental mixing equipment is the type of fluid being used. For fresh water or produced formation water, the need for a premix tank may not exist. For a viscosified fluid system, the premix tank will prove to be an asset, and will provide the following benefits:
• allow the operator to circulate the hole and mix kill fluid at the same time.
• allow continuous agitation of fluids at surface.
• provide extra fluid storage capacity.
• reduce mixing time when used in conjunction with Service Rig mixing equipment.

2.5.2.8 Sour Fluid Storage

IRP  Sour fluid storage tanks are required for storage of all sour fluids.

NOTE: Storage tanks containing sour fluids or sour gasified fluids must:
• Be grounded and bonded.
• Be purged prior to storing sour fluids.
• Have mechanical gauge for gauging tank level.
• Be equipped with connections for circulating the tank to add scavengers and for unloading.
• Be equipped with steam coils during winter operations to prevent fluids from freezing and steam contamination.
• Have a flame arrestor installed on the storage tank vent line at the base of the flare stack.

2.5.3 COMPLETION AND WORKOVER FLUIDS

2.5.3.1 Definition

NOTE: The primary function of a completion or workover fluid is to control formation pressure, transport movable solids and minimize formation damage.

Selection of completion or workover fluids is determined on site-specific operations and well conditions. Completion and workover fluids required can range from complex high density viscosified fluids to fluids such as fresh water, brines or hydrocarbon-based fluids. Caution should be taken while using hydrocarbon fluids as risk of well control can be increased, by reducing warning signs of kicks, increasing solubility of H2S, and slowing reaction time of scavengers.
2.5.3.2 Dissolved Sulphide

The presence of dissolved sulphides in the completion or workover fluid must be determined. Dissolved sulphide levels of 10 ppm or greater must be treated with scavengers prior to circulating to an open system.

NOTE: A decrease in pH in a water-based fluid is an indicator that sulphides may be present in the fluids.

The Hach Test and Garrett Gas Train are used to detect the presence of sulphides. The Garrett Gas Train is a quantitative method of determining the amount of dissolved sulphides.

Dissolved sulphides in the completion fluids must be monitored by a Completion Fluids Engineer. When the Completion Fluids Engineer is not on location, the operator’s representative, the derrickman or the safety man will be responsible for checking to determine if soluble sulphides are contained in the completion fluids.¹

2.5.3.3. Completion Fluid Volume and Storage

IRP All fluid volumes on location are to be monitored and recorded to ensure the volume of usable completion fluid to control the well is the hole volume, plus a surface backup volume of 100% of hole volume plus tank bottoms.

NOTE: The fluid volumes must be monitored and recorded at the start of each crew change, before and after filling the hole, circulating, and tripping.

Prior to commencing an operation it is the intent to have 200% of active hole volume on surface and maintain 100% of active hole volume on surface at all times. Completion fluid storage capacity on location can include the rig tank and the premix tank.

For winter operations, storage tanks must be adequately heated to prevent freezing. Storage tanks equipped with properly maintained steam coils will prevent freezing and steam contamination of fluids.

2.5.3.4 Fluid Density

IRP Density of the completion fluid must be maintained at a minimum 1400 kPa overbalance of the formation pressure.

NOTE: The density and viscosity of the completion fluid should be checked and recorded at the start of each crew change, prior to filling hole, circulating or tripping, and when circulating bottoms up or when completion fluid is contaminated.
2.5.3.5 Packer Fluids

IRP

Packer fluids must be inhibited to prevent corrosion.

NOTE: Corrosion inhibitors should be soluble and premixed in the packer fluid and circulated into the annulus.

Water based packer fluids should also contain oxygen scavengers and biocides.

Solids-free packer fluids are recommended.

Diesel fuel is commonly used to top off the annulus to prevent surface freezing.

2.5.4 Safety and Handling

2.5.4.1 Safety

A safety meeting must be held with all personnel on location prior to commencing operation and prior to any hazardous operation.¹ ¹

2.5.4.2 Handling

Written procedures and fluid specifications must be on location for safe handling and mixing of the completion/workover fluid. The need for shower facilities should be determined at the pre-job risk assessment meeting using MSDS data.

Transportation of Dangerous Goods, WHMIS and applicable provincial Occupational Health and Safety regulations must be adhered to. Material Safety Data Sheets (MSDS) must be current, and available for use on site.

NOTE: The Enform Well Service BOP manual describes circulation methods and kill procedures.
List of References

4. DACC, IRP Volume 14 - Non Water Based Drilling and Completion Fluids, 2004, Calgary, Alberta.
2.6 BRAIDED WIRELINE OPERATIONS

2.6.1 SCOPE

2.6.1.1 The Electrical and/or Braided Wireline Operations Alberta Recommended Practices (ARP’s) were originally developed by the Blowout Prevention Well Servicing Committee (BPWSC) in 1989 and updated by the Industry Recommended Practices (IRP) Volume 2 Review Committee in 2003. The recommendations are for critical sour well completion and servicing activities and environment, recognizing the need for equipment integrity during both routine completion and servicing conditions and those conditions which could be encountered during well control operations.

The equipment considered includes all equipment, which forms an integral part of the pressure control equipment directly attached to the BOP stack or wellhead.

2.6.1.2 Throughout this section IRPs are highlighted in bold type and the word “shall” or "must" is used. Additional best practices are not highlighted and contain the words “should” or “recommended”.

2.6.1.3 In cases of inconsistency or conflict between any of the recommended practices contained in this IRP and applicable legislative requirements, the legislative requirements shall prevail.

2.6.2 RIG UP/RIG OUT

IRP Conduct a safety meeting with the operator’s representative(s), wireline crews and all other personnel on lease to discuss the operations at hand, to designate responsibilities, discuss emergency contingency plan, and discuss other appropriate safety considerations.

Prior to any work commencing at the well head the proper air supply equipment and safety personnel shall be in place. All respiratory masks must be fit tested prior to use. The air supply equipment should be worn when installing, bleeding off and breaking out the pressure control system and kept on until the well head is shut in and secure.
NOTE: IRP 2.12 Safety addresses general matters to be considered during the safety meeting. Matters specific to wireline operations include:

- Prior to commencing rig up, the well pressure shall be checked to ensure that the pressure control equipment is rated for the working pressure.
- The wireline truck must be spotted a minimum distance of 25 m from the wellhead. The equipment should not be placed downwind of the wellhead.
- If possible, the equipment should be moved or operations shut down when a changing wind direction is detrimental to a safe operation.
- All essential equipment required for the wireline operation shall be equipped with positive air shut off valves.
- Lubricator bleed off lines shall be tied into a flare stack.
- The lubricator system shall have adequate support to prevent lateral movement, and should not be left unattended.
- Pickers, mast units, rigs and wireline units shall be grounded to equal potential between the flow lines, wellhead and all equipment

2.6.3 Wellsite Pressure Tests

IRP After the wireline BOPs are installed on the wellhead, they shall be pressure tested from below with the rams closed on a test rod to a pressure the lesser of:

- 1.3 times the estimated maximum potential Shut-in Tubing Head Pressure (SITHP), or
- to the manufacturers wellhead pressure rating.

If for any reason the BOPs or any lubricator connections are broke open during the course of the job then the BOPs and lubricator shall be re-pressure tested every time.

A pre job pressure test shall be performed on the wireline pressure control system after connection to the wellhead, using a low viscosity non flammable fluid. Pressure test the equipment for 10 minutes to 1400 kPa, then pressure test for 10 minutes to the lesser of:

- 1.3 times the estimated maximum potential SITHP, or
• to the equipment manufacturers specified pressure rating.

Ensure that all equipment components are pressure compatible.

NOTE: When possible the lubricator assembly should always be pre-job pressure tested in a vertical position. If the lubricator is on top of the rig’s BOP stack and the pressure test cannot be done due to the BOP not holding pressure from the top, then pressure testing of the lubricator assembly in a horizontal position is acceptable.

If a pressure test can be conducted on top of the rig’s BOP stack, care must be taken to ensure that the top of the Annular Preventer rubber on the rig’s BOP assembly does not become contaminated or damaged. (An Annular Preventer is not designed to support pressure from the top. Also, any dirt, sand, etc. will damage the rubber if the Annular Preventer is operated.)

The wellhead shall be pressure tested every time after the lubricator has been removed and each time the wellhead is reassembled, as outlined in IRP 2.1 Wellheads.

2.6.4 Routine Inspection Tests

IRP The wireline BOPs shall be serviced immediately after use and also pressure tested prior to working on any critical well. For routine maintenance tests the BOPs shall be tested to their rated working pressures with the rams at open and closed positions.

A complete record with information on equipment material specifications, all pressure tests conducted and all seal changes shall be available on site for inspection upon request.

Non-destructive testing shall be done on the pressure control equipment annually. All annual tests shall be done to the manufacturers maximum recommended pressures. The testing shall be performed by qualified personnel in accordance with the manufacturer’s specifications. Full documentation shall state all tests performed, by whom they were performed, testing procedures used and any alteration specifications. Full documentation must be available for inspection upon request.
2.6.5 Pressure Control Equipment

2.6.5.1 Equipment Specifications
IRP
Grease injection systems shall be used on all licensed critical wells open to flow with known or expected pressure present at the wellhead.

A dual BOP system is acceptable for wells up to 35 MPa working pressure. Wells exceeding 35 MPa shall require a third BOP including properly rated hoses and connectors for the applicable working pressures. The third or middle set of BOPs shall be configured to hold pressure from below and shall be used for back up only. (Refer to Appendix A)

All pressure equipment shall be tagged with a non-destructive identification band with a complete record of pressure ratings and last inspection date.

2.6.5.2 Equipment Configuration
IRP
Appendix A shows the recommended configuration for equipment used in electric/braided line operations.

- The connection to the wellhead shall be flanged.
- The remote controls for the BOPs shall be a minimum of 25 m from the wellhead.
- The grease injection port between BOPs shall be connected to grease supply hose installed with check valves.
- The upper BOP shall always hold pressure from below.
- The length of the lubricator above the BOPs shall be sufficient to accommodate operations as planned.
- The pressure control equipment shall include a bleed-off port and gauge outlet, both of which must be isolated from well pressures by high pressure sour service valves.
- Bleeding off the lubricator shall be done via the flare system.
- A velocity check valve shall be installed at the top of the lubricator just below the grease head to ensure a seal in the event of loss of cable from grease head.
• Grease head flow tubes shall be close-fitting to the wireline in order to minimize the amount of grease needed to affect a good seal. The number of flow tubes required will depend on the wellhead pressure.

• The grease injection supply port shall be equipped with a check valve.

• The grease head bleed off hose shall be equipped with an isolation valve a minimum of three metres from the discharge end. The bleed off hose shall be tied down at ground level and terminate a minimum of 15 metres downwind from wellhead. Should quick connectors be used, they shall include a seal, which is activated when disconnected.

• All grease supply manifolds, hand pumps and accumulator systems shall be remotely operated a minimum distance of 25 metres upwind from the wellhead.

• A line-wiper is recommended for cleaning the wireline. The pack-off head should only be used in the event of a seal loss and when the wireline is stationary.

• Grease pump number one shall supply the grease head to control wellhead pressure and be complete with an independent grease supply.

• Grease pump number two shall provide back up for pump number one in the event of a failure. Pump number two shall also supply grease injection between the upper set of BOP rams and the lower set of BOP rams. It shall also have an independent grease supply.

• A grease supply manifold is required for fast change over of grease pumps in the advent of a failure of either system.

• Quick union connections with elastomeric seals and Acme threads are required for connections above the wellhead flange.

**NOTE:** When the top set of BOPs are installed to hold pressure from below and the bottom set of BOPs are installed with the rams inverted to hold pressure from above and both BOPs closed on the line, then grease injected between the BOPs is contained and seals the line blocking migration of gas through the cable. With This configuration only one set of BOPs contains the well but, makes it possible to obtain greater than
wellhead pressures with a minimum grease/oil loss. If however the lower BOPs are installed to hold pressure from below, then grease injected between the BOPs may leak past the lower BOPs into the well. With this configuration, once the wellhead pressures are equalized the grease/oil loss is greater.

- Pressure control systems with pressure ratings up to 69 MPa require two 13 mm NPT bleed-offs/equalization connections.
- 69 MPa and higher rated pressure control equipment require two staggered API Type 1, Type II or Type III high pressure test or bleed-off connections.
- All connections shall be elastomerically sealed with metal-to-metal premium threaded connections or be an integral union type.
- A 50.8 mm pump-in sub including plug valves shall be installed below the bottom BOP and above the wellhead for well control.
- The grease head flow tubes shall be sized correctly to the wireline to ensure a proper friction seal can be maintained. Selection of flow tubes is important for an optimum seal and to reduce grease consumption.
- A line wiper should be considered for stripping the wireline and be remotely operated from a minimum distance of 25 metres from wellhead.

### 2.6.5.3 Material Specifications

**IRP**  
All metallic pressure control equipment which may be exposed to sour effluent must be certified as being manufactured from materials meeting the requirements of NACE MR0175/ISO, latest edition.¹ (Appendix B details recommended material specifications).

**NOTE:** Standard service braided wireline is not recommended, but is acceptable when the well is in an overbalanced situation and there are no sour effluents in the wellbore fluids.

Inhibitors should be applied when using a non H₂S-rated wireline.
2.6.5.4 Elastomer Specifications

IRP   Elastomeric seals should be selected utilizing the recommendations set out in IRP 2.11 - Guidelines for Selecting Elastomeric Seals.

NOTE:  There are a number of subcomponents, which are constructed of non metallic material. These include the annular preventer and ram rubbers, bonnet or door seals and packing for BOP secondary seals.

With elastomeric seals, compatibility must exist between the pressure testing fluids or any other fluid that may come into contact with the seals.

2.6.5.5 Bolting

IRP   Bolting as specified in IRP 2.1 - Wellheads, Appendix E shall be utilized.

2.6.5.6 Certification

IRP   All equipment subjected to pressure and H₂S environments must, have a unique identifier (serial number) and a legible non-destructible stamp or other permanent marking to indicate it is suitable for H₂S service. Pressure control equipment must be traceable to the manufacturer or to the last qualification. An equipment record should be kept and be available for inspection on location.
APPENDIX A.

Figure 1. Wellhead Control Equipment
Figure 2. Velocity Check Valve
## APPENDIX B. WIRELINE SERVICING EQUIPMENT

### Materials Recommended

<table>
<thead>
<tr>
<th>Components</th>
<th>Minimum Recommended Standards</th>
<th>Typical Material Types Used</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Wireline BOPs</td>
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<tr>
<td>Wellhead Flange</td>
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<td>API 6A</td>
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<td>Bolting</td>
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<td>Users should be aware that flange size restrictions apply when using reduced yield strength bolting (i.e. A320 L7M) - See Table 49, API 6A, latest edition, to avoid derating, A453 GRADE 660 OR CRA bolting must be used.</td>
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<td>Gasket</td>
<td>API 6A</td>
<td>316 OR 304 STAINLESS STEEL</td>
<td>Austenitic stainless steel gasket material NACE MR0175 must be in annealed condition.</td>
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<td>O-Rings NACE MR0175 latest edition</td>
<td>BITON</td>
<td>Reference IRP 2.11 Elastomer guide</td>
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<td>Ball: NACE MR0175 latest edition</td>
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<td>AISI/SAE 4130-4140</td>
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<td>Packing Element: NITRILE, VITON</td>
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<td>Reference IRP 2.11 Elastomer guide for limitations application.</td>
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<td>5. Wireline</td>
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<td>Wireline corrosion inhibitor is normally used</td>
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</table>
NOTES:

1. API 6A refers to the latest edition.

2. NACE MR-01-75 refers to the latest edition.

3. The focus of the IRP Volume 2 Review Committee has been to recommend MINIMUM standards for materials to be used for critical sour service. These recommendations are primarily designed to prevent Sulfide Stress Corrosion Cracking because it can result in the “rapid” failure of metals. Similarly (as noted in the NACE MR0175 Specification, latest edition) austenitic stainless steels can fail rapidly from chloride stress corrosion cracking in certain environments. However, the material selection for resisting the many forms of weight loss corrosion is left as an economic decision to be made by the equipment owner or well operator.
List of References


2.7 SLICKLINE OPERATIONS

2.7.1 SCOPE

2.7.1.1 The Slickline Alberta Recommended Practices (ARP’s) were originally developed by the DACC Subcommittee in 1989, and updated by the Industry Recommended Practices (IRP) Volume 2 Review Committee in 2003, with the intention of providing guidelines for slickline operations on critical sour wells. Key issues related to equipment requirements, rigging in procedures, pressure testing, equipment servicing and reporting are specifically addressed. An Appendix has been included to provide technical information related to mechanical properties and strengths and operational considerations associated with the equipment.

2.7.1.2 Throughout this section IRPs are highlighted in bold type and the word “shall” or “must” is used. Additional best practices are not highlighted and contain the words “should” or “recommended”.

2.7.1.3 In cases of inconsistency or conflict between any of the recommended practices contained in this IRP and applicable legislative requirements, the legislative requirements shall prevail.

2.7.2 RIG UP/RIG OUT

IRP Conduct a safety meeting with the operator's representative(s), wireline crews, and all other personnel on lease. Discuss the planned slickline operation, the emergency response plan, any appropriate safety considerations, and designate personnel responsibilities.

The Operator shall provide adequate breathing air for all personnel on location. Breathing apparatus shall be used whenever the pressure containing equipment is open to atmosphere. Breathing apparatus shall be used until the wellhead is secure and the area has been checked for H2S. Refer to IRP section 2.12 “SAFETY” for more information on breathing air requirements.

Under no circumstances are “gin poles” to be used to support slickline equipment.
Climbing on the lubricator shall not be allowed.

All equipment attached to the wellhead must be adequately supported to prevent lateral movement.

**NOTE:** IRP section 2.12, Safety, addresses general matters to be considered during the safety meeting. Matters specific to wireline operators to be addressed include:

- The pressure control equipment must be rated for the working pressure.
- The wireline truck shall be spotted a minimum distance of 25 m from the wellhead or equipped with a diesel engine with an air shut off. The equipment should not be placed downwind of the wellhead. In case of a wind direction change, the wireline unit should be moved if the wind is detrimental to a safe operation.
- The crane or mast unit must be grounded or bonded to equal potential between the flow lines, wellhead, and all equipment.
- The lubricator is full length and supported to prevent any lateral movement, and shall never be left unmonitored.

In freezing conditions, precautions should be taken to prevent elastomeric failure and inhibit the formation of gas hydrates in the surface equipment. The slickline BOPs shall be adequately heated to keep the elastomers operational.

**2.7.3 WELLSITE PRESSURE TESTS**

**IRP** After BOPs are installed on the wellhead, wireline BOPs are to be pressure tested from below with the rams closed. The wireline BOPs shall be tested to 1400 kPa for 10 minutes and a higher pressure for 10 minutes. The higher pressure shall be the lesser of:

- \( 1.3 \times \) the maximum potential Shut-in Tubing Head Pressure (SITHP), or
- the maximum working pressure of the wellhead.

The BOP pressure test shall be conducted prior to each job using a low viscosity, non-flammable, non-freezing fluid.
A pre job pressure test shall be performed on the wireline pressure control system (i.e. lubricator, stuffing box, or grease injection) after connection to the wellhead, using a low viscosity non flammable fluid. The wireline pressure control system shall be tested to 1400 kPa for 10 minutes and a higher pressure for 10 minutes. The higher pressure shall be the lesser of:

- 1.3 x the maximum potential SITHP, or
- the maximum working pressure of the wellhead.

This pressure test shall be conducted every time the pressure control system has been opened to atmosphere.

**NOTE:** Any wellhead parts that have been removed for the installation of the wireline equipment (i.e. wellhead cap) must be pressure tested after the wellhead has been reassembled, as outlined in IRP 2.1 Wellheads.

It is recommended that the equalizing equipment on the slickline BOPs be function tested during the pressure testing procedure.

On wells where the maximum potential Shut-in Tubing Head Pressure (SITHP) is not well established through past operations, it is recommended that the wireline pressure control equipment be tested to the maximum working pressure of the wellhead connection.

### 2.7.4 Routine Inspection Tests

**IRP** The wireline BOPs shall be subjected to a certification pressure prior to working on a critical well or after being redressed. The BOPs shall be tested up to the BOP working pressure with the rams open and with the rams closed.

The lubricator and all related equipment shall be pressure tested to the working pressure prior to working on a critical well.

All records with equipment material specifications, all pressure tests conducted, and elastomeric seal changes are to be kept with the equipment. These records must be available on site for inspection.

Pressure control equipment subject to alteration and repairs requiring welding shall be inspected using the materials evaluation methods described in IRP 2.10 Quality Programs.
NOTE: Non destructive evaluation as described in Appendix A of IRP 2.10 Quality Programs shall be done on the pressure control equipment annually. The equipment must be certified by qualified personnel. The certification is to be available for inspection.

2.7.5 EQUIPMENT

2.7.5.1 Equipment Specifications

IRP Slickline equipment specifications shall include the following:

A) The lubricator length, diameter, and pressure rating must be adequate for the services to be provided. The pressure rating of the pressure control equipment must be a minimum 1.3 x the maximum expected wellhead pressure. Specific requirements include:

1. 103 MPa or higher pressure lubricator
   • Requires two opposed API Type I, Type II or Type III high pressure needle valve bleed off connections.
   • All connections must be O-ring sealed or have a metal sealed connection with a premium thread.

2. 69 MPa lubricator
   • Requires two opposed 13 mm (1/2 inch) NPT needle valve bleed off connections.
   • All connections must be O-ring sealed or have a metal sealed connection with premium thread.

3. 35 MPa lubricator
   • Requires two 13 mm (1/2 inch) NPT needle valve bleed off connections.
   • All connections must be O-ring sealed or have a metal sealed connection with a premium thread.

4. 21 MPa lubricator
   • Requires two 13 mm (1/2 inch) NPT needle valve bleed off connections.
   • The minimum standard connections are API tubing threads, modified with elastomeric sealed connections.

B) All metallic pressure control equipment which may be exposed to sour effluent must be certified as meeting the
requirements of the most recent revision of ANSI/NACE MR0175. Appendix B details recommended materials specifications.

2.7.5.2 Equipment Configuration

IRP Appendix A, illustrates the recommended configuration for equipment used in slickline operations.

The length of the lubricator above the BOPs shall be sufficient to accommodate operations as planned.

As a minimum, one wireline BOP located between the lubricator and the wellhead must be used in the pressure control equipment. All BOPs must be remotely operated a minimum of 25 m from the wellhead using an adequately sized accumulator.

The hydraulic stuffing box or high pressure pack off must be remotely operated a minimum of 25 m upwind from the wellhead. If grease injection is being used in conjunction with the slickline, refer to IRP 2.6 Electric Wireline for grease injection requirements.

Any de-pressuring of the lubricator shall be done through the flare system.

Hammer union connections shall not be used for any connection to the wellhead or wireline pressure equipment.

There must be unobstructed access to kill the well below the BOP either via the wellhead or a pump-in sub.

Connection at the wellhead must be a flanged connection.

When connecting the wireline pressure control equipment to a tubing string during servicing operations, a full-bore working valve must be installed below the slickline BOPs using a proper threaded connection.

NOTE: Quick union (non-hammer union) connections with elastomeric seals are acceptable for connections above the flanged connection to the wellhead.
2.7.5.3 Elastomeric Specification

**IRP** Elastomeric seals shall be selected utilizing the recommendations set out in IRP 2.11 Guidelines for Selecting Elastomer Seals.

**NOTE:** With elastomeric seals, compatibility must exist between the seals and the pressure testing fluids, or any other fluid that may come in contact with the seals.

There are a number of subcomponents that are constructed of non metallic material. Compatibility must exist between these components and the pressure testing fluids, or any other fluid that may come in contact with these components. These include the annular preventor, ram rubbers, and bonnet or door seals and packing for BOP secondary seals.

2.7.5.4 Bolting

**IRP** Bolting as specified in Appendix B shall be utilized.

2.7.5.5 Certification

**IRP** All equipment subjected to pressure and H₂S environments must have a unique identifier (serial number) and a legible stamp or other permanent marking to indicate it is suitable for H₂S service. Pressure control equipment must be traceable to the manufacturer or to the last qualification. An equipment record shall be kept and be available for inspection.

**NOTE:** Section 5.4 of the most recent revision of ANSI/NACE MR0175¹ – details acceptable identification stamping procedures.
APPENDIX A. SLICKLINE WELLHEAD EQUIPMENT

Figure 1. Slickline Wellhead Control Equipment
# APPENDIX B. WIRELINE SERVICING EQUIPMENT MATERIALS RECOMMENDATIONS

<table>
<thead>
<tr>
<th>Components</th>
<th>Minimum Recommended Standards</th>
<th>Typical Material Types Used</th>
<th>Comments</th>
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<tbody>
<tr>
<td>1. Wireline BOPs</td>
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<tr>
<td>- Wellhead Flange</td>
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<td>AISI/SAE 4130-4140, L-80</td>
<td>Users should be aware that flange size restrictions apply when using reduced yield strength bolting (i.e. A320 L7M) - See table X C1, API 6A, latest edition. To avoid derating, A453 GRADE 660 or CRA bolting must be used.</td>
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<td>- Gasket</td>
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<td>316 OR 304 STAINLESS STEEL</td>
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<td>Upper and Lower BOPs</td>
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<td>Reference IRP 2.11 elastomer guide for limitations in application.</td>
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<td>Reference IRP 2.11 Elastomer Guide for limitations in application.</td>
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<td><strong>Specific materials for the specific environment.</strong></td>
<td>Wireline corrosion inhibitor is normally used.</td>
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</table>
Notes:
1. API 6A REFERS to 15th Ed. 1 April 1986.

2. The focus of the IRP 2 Review Committee has been to recommend MINIMUM standards for materials to be used for critical sour service. These recommendations are primarily designed to prevent Sulphide Stress Corrosion Cracking because it can result in the “rapid” failure of metals. Similarly (as noted in the ANSI/NACE MR0175, latest edition, austenitic stainless steels can fail rapidly from chloride stress corrosion cracking in certain environments. However, the material selection for resisting the many forms of weight loss corrosion is left as an economic decision to be made by the equipment owner or well operator.
List of References

2.8 SNABBING OPERATIONS

2.8.1 SCOPE

2.8.1.1
This IRP chapter has been developed under the auspices of the Drilling and Completions Committee (DACC). 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 Snubbing Operations during routine completion and servicing conditions on Critical Sour Wells (Refer to IRP Volume 15 - Snubbing Operations). Accordingly, no specific consideration was given for the application of snubbing during well control operations which may occur while drilling a new well.

2.8.1.2
The primary purpose of snubbing is for conducting servicing or completion operations on a live well with or without the wellhead removed. It will be necessary to install an appropriate well servicing BOP stack on the wellhead prior to installing the snubbing stack. This BOP stack and its associated controls must function independent of the snubbing stack and meet all the requirements of normal well servicing operations.

2.8.1.3
This IRP is part of a series. For the overall intent of, and as a general reference to the whole series, refer to IRP 2.0. The recommendations contained in this IRP provide operators with industry endorsed advice, and are intended to be applied in association with all existing government regulations as well as the other IRPs. While strict legal enforcement of good practices is not desired or possible, such practices place considerable onus on the legally responsible party to comply or otherwise provide a technically equivalent or better solution.

2.8.1.4
While the recommendations set out in this IRP are meant to allow flexibility, the need for exercising competent technical judgment is a necessary requirement to be employed concurrently with its use.

2.8.1.5
Throughout this section IRPs are highlighted in bold type and the word “shall” or “must” is used. Additional best practices are not highlighted and contain the words “should” or “recommended”.
2.8.2 Pre-Rig-In

IRP Prior to moving any Snubbing equipment onto the location, the following items must be addressed:

The Operating Company and Service Company will review the Equipment Service Log and ensure that:

• The snubbing/stripping preventers have been shop pressure tested immediately prior to being utilized on the critical sour well as per IRP 2.8.5

• All pressure control components of the snubbing equipment including preventers and equalizing lines have been inspected, shop serviced and hydrostatically tested within the last 12 months or 250 hours of sour fluid exposure as per IRP 2.8.5

• Documentation for the elastomers composing the Snubbing Stack Rams shall be reviewed to ensure they are adequate for the job as per IRP 2.11.4

• The Accumulator specifications are available and accumulator-sizing calculations have been performed.

• The Operating Company Representative will indoctrinate the Service Company Representatives prior to moving onto the location. Items to be reviewed will include general safety issues, hazards identification on location (rat holes, high pressure piping, etc), muster stations and egress routes.

The Operating Company and Service Company will review the well parameters including:

• Pressures
• Gas composition (especially H$_2$S and CO$_2$ concentrations)
• Salinity of produced water
• Hydrate formation
• Condensate
• Sulphur, Iron Sulfide and other Scales
• Wax
• Asphalt content
• Wind direction

The Operating Company and Service Company will review proposed equipment layout and spacing requirements with respect to company and government spacing regulations.

2.8.3 Rig-Up

Prior to commencing the operation, a safety meeting shall be held to discuss the operations at hand, delegate responsibilities, emergency plans, as well as other safety considerations. The meeting shall include the oil company representative(s), the safety company supervisor, the rig crew, the snubbing crew and all other personnel on the lease involved in the day to day operation.

All hydraulic lines, testing lines and kill lines must be organized and kept tidy so they don’t interfere with an emergency evacuation of the area.

All equipment attached to the wellhead must be adequately supported to prevent lateral movement.

The snubbing unit can only be left unattended during an operation while connected to the wellhead if all the following conditions apply:

• The pipe in the hole is not in a pipe–light environment.
• The pipe has two tubing plugs in place as per IRP 2.8.7
• The pipe has been landed with a tubing hanger with the lag screws engaged.
• The stripping pipe rams are closed and locked.
• The safety pipe rams are closed and locked.
• A NACE Trim Stabbing Valve in the closed position must be installed on the tubing.
2.8.4 WELLSITE PRESSURE TEST

IRP  The following pressure tests shall be conducted on the snubbing equipment with a low viscosity non flammable fluid (nitrogen is acceptable) prior to exposing it to wellbore fluids:

- Pressure test the safety/primary* annular preventer to 1400 kPa for 10 minutes and to the lesser of 1.1 times expected bottomhole pressure or the wellhead pressure rating for 10 minutes.

- Pressure test all safety/primary* pipe ram preventers to 1400 kPa for 10 minutes and to the lesser of 1.1 times expected bottomhole pressure or the wellhead pressure rating for 10 minutes.

- Pressure test stripping preventers**, bleed off and equalizing lines and the stabbing valve to 1400 kPa for 10 minutes and to the lesser of 1.1 times expected bottomhole pressure or the wellhead pressure rating for 10 minutes.

- Prior to running tubing into the snubbing stack, pressure test the tubing plug from the bottom to 1400 kPa for 10 minutes and to 1.1 times expected bottomhole pressure for 10 minutes.

- Prior to tripping pipe out of the well the tubing plug shall be tested from below to a minimum of 90% bottomhole pressure. However, when it is impractical or impossible, a pressure test from the top equal to a differential across the plug which is at least 1.1 times bottomhole pressure shall be performed.

- All pressure tests must be recorded in a log or tour report.

NOTE: When pressure testing the blanking plug in the tubing string, consideration should be made not to exceed the allowable design factors over the entire length of the tubing string (refer to IRP 2.4 for design factor details).

* Safety/primary preventers are defined as the parts of the primary BOP stack which are located between the snubbing/stripping preventers and the wellhead.
** Stripping preventers are components of the snubbing system including the stripping pipe rams and stripping annular preventer which are cycled to facilitate stripping or snubbing into or out of the live well.

When performing the shell test on the snubbing stack, note any pressure leak-off into the hydraulic system of the Annular Preventer. If a leak is detected it can be easily repaired with a new seal.

If a pressure test can be conducted on top of the rig’s BOP stack, care must be taken to ensure that the top of the Annular Preventer rubber on the rig’s BOP assembly does not become contaminated or damaged. (An Annular Preventer is not designed to support pressure from the top. Also, any dirt, sand, etc. will damage the rubber if the Annular Preventer is operated.)

2.8.5 **Routine Inspection And Tests**

**IRP** The snubbing/stripping preventers shall be shop pressure tested to their working pressure immediately prior to being utilized on a critical sour well or after being redressed.

All pressure control components of the snubbing stack including preventers and equalizing lines shall be inspected, shop serviced and hydrostatically tested to manufacturer’s specifications within the last 12 months or after 250 hours of sour fluid exposure, whichever occurs first.

The inspection, shop servicing and hydrostatic testing must be performed in accordance with IRP 2.10 “Quality Programs” by an API licensed manufacturer or by a company that meets the requirements of IRP 2.10.2.2

Pressure control equipment subject to alterations or repairs requiring welding shall be inspected using the materials evaluation methods described in IRP 2.10, “Quality Programs”.

The inspection test procedure and results shall be documented and any parts that are replaced must be traceable to origin or last qualification. Documentation shall indicate the type of marking placed on the equipment as proof of the test.

Documentation of the shop test shall be available on location in the unit log including elastomeric seal changes complete with verification of elastomer type. Traceable identification (i.e.
batch number) shall also be available upon request from the service company base.

2.8.6 Equipment

2.8.6.1 Equipment Pressure Rating

IRP All pressure control equipment including stripping/ snubbing preventers, the equalizing loop and bleed line will have a working pressure equal to the lesser of 1.1 times bottomhole pressure or the wellhead pressure rating.

2.8.6.2 Equipment Configuration

IRP Stack Configuration 1 outlined in Figure 1 of Appendix A will consist of one stripping annular preventer and one stripping pipe ram preventer mounted on top of a safety/primary BOP stack.

Stack Configuration 1 will be allowed for snubbing or stripping of Collared Pipe if pressures and pipe sizes do not exceed the guidelines given below:

- 60.3 mm up to 13,800 kPa (2000 psi)
- 73.0 mm up to 12,250 kPa (1750 psi)
- 88.9 mm up to 4,000 kPa (600 psi)

Consideration shall be given to Stack Configuration 2 if temperatures are cold or if external pipe conditions are poor.

Snubbing of pipe with integral connections will be allowed through Stack Configuration 1 as long as pipe size does not exceed 88.9 mm and pressures do not exceed 20,689 kPa (3000 psi).

Stack Configuration 2 outlined in Figure 2 of Appendix A will consist of one stripping annular preventer and two stripping pipe ram preventer mounted on top of a safety/primary BOP Stack. With this configuration the two stripping pipe rams would be used to snub or strip the pipe.

Stack Configuration 2 will be the minimum acceptable Stack Configuration for snubbing of Collared Pipe if pipe sizes or pressures exceed those listed above.
Stack Configuration 2 will be the minimum acceptable Stack Configuration for snubbing pipe with integral connections if pipe size exceeds 88.9 mm or pressures exceed 20 689 kPa (3 000 psi).

If there is a possibility that the safety/primary BOP elastomers will be exposed to an incompatible fluid or gas mixture, a nitrogen gas or sweet gas purge shall be applied across the safety/primary BOPs as illustrated in Figure 3 of Appendix A. The purge must be injected below the lowest Stripping Preventer.

A stabbing valve with appropriate crossover subs must be readily available in the snubbing basket.

The connection between the snubbing stack and the safety/primary BOPs must be flanged.

All connections of the pressure control equipment including stripping/snubbing preventers, the equalizing loop and bleed-lines must either be flanged or if threaded connections are used, the threads must be isolated from the wellbore environment by seals. EUE type connections will only be acceptable to 21 MPa working pressure. NPT threads are acceptable to a maximum pipe O.D. of 25.4 mm in accordance with API Specification 6A (Sec. 4.2.1.2, Table 1). Hammer unions are not acceptable.

2.8.6.3 Accumulator System Requirements

IRP The snubbing stack accumulator must have sufficient usable fluid available that allows two functions of a single gate preventer, and two functions of the actuators for bleeding off equalized plug valves with the annular preventer closed. After these functions a minimum pressure of 8400 kPa must remain on the accumulator circuit.

The snubbing stack accumulator must be able to maintain closure of the annular preventer for a minimum of ten minutes and maintain a minimum of 8400 kPa with no power from the recharge pump.

Accumulator sizing calculations must be completed and verified by the Operator’s wellsite representative prior to pressure testing the snubbing stack on location. Records of calculations must accompany the accumulator to the location.
The pre-charge pressure of each accumulator bottle shall be checked and recorded immediately prior to each job.

Snubbing stack accumulator specifications must be available for review on location. The specifications would include: accumulator make, number of bottles, capacity, design pressure and operating pressure (upstream of any regulators).

Requirements for the safety BOP accumulator specifications are given in IRP 2.2 “Service Rig BOP Stack, Accumulator and Manifold”

2.8.6.4 Back-up Nitrogen Supply

IRP Sufficient usable nitrogen must be available, at a minimum pressure of 8400 kPa, to fully close all snubbing stack rams (including “redundant equipment”).

2.8.6.5 Accumulator Control Locations

IRP The accumulator for the snubbing stack must be equipped with master controls that operate each preventer and are located in a readily accessible location near the operator’s position in the snubbing basket.

The accumulator for the safety/primary BOP stack must be equipped with master controls that operate each preventer and are located in a readily accessible location near the operator’s position.

An independent accumulator system with operating controls for each preventer of the safety/primary BOP stack must be located a minimum of 25 metres from the well, shielded or housed to protect the operator from flow from the well.

2.8.6.6 Material Specifications

IRP All metallic pressure control equipment which may be exposed to sour effluent must be certified as being manufactured from materials meeting the requirements of NACE MR0175, latest edition.¹

2.8.6.7 Elastomer Specifications

Compatibility of any elastomer seal with the intended service environment shall be determined when selecting materials and equipment for the completion and/or servicing of a critical sour well. This includes consideration of the effect of any fluid or substance that the
elastomer seals may be exposed to as well as ambient temperatures at which seals are required to perform.

Reference shall be made to IRP 2.11 “Guidelines for Selecting Elastomeric Seals”, for information on common elastomers and servicing guidelines.

NOTE: Compatibility must exist between the elastomeric seals and the pressure testing fluids or any other fluid that may come in contact with the seals.

There are a number of subcomponents which are constructed of non metallic components. These include the annular preventer and ram rubbers, bonnet or door seals and packing for BOP secondary seals.

2.8.6.8 Bolting

IRP External Bolting as specified in Appendix E of IRP 2.1, Wellheads, shall be utilized.

2.8.6.9 Equipment Certification

IRP All equipment subjected to pressure and H₂S environments must have a unique identifier (serial number) and a legible stamp or other permanent marking to indicate it is suitable for H₂S service. Pressure control equipment must be traceable to the manufacturer or to the last qualification. An equipment record shall be kept and be available for inspection.

NOTE: Section 5.4 of NACE MR0175, latest edition details acceptable identification stamping procedures.

2.8.7 Operating Procedures

IRP No personnel shall be allowed in the rig derrick while snubbing operations are being conducted.

Snubbing and stripping shall be allowed after dark with daylight-equivalent lighting.

Prior to tripping out of the well, all sour fluids must be displaced from the tubing with a non-flammable gas or fluid.

The tubing string must be equipped with a minimum of one primary and one secondary internal pressure control devices before the tubing string can be deployed into or out-of a well.
Positive locking tubing plugs landed in profiled nipples and tubing bridge plugs are acceptable internal pressure control devices. Hook wall type plugs are not acceptable.

All gas vented during the snubbing/stripping operation must be flared and burned a minimum of 50 m from the well. Proper equipment such as flame arresters and other precautions must be used to prevent flashbacks from vented gases.

NOTE: The tubing plug must have a pressure rating which is equal to or greater than 1.1 times the bottomhole pressure. IRP 2.3 “Downhole Equipment”, provides recommendations regarding plugs and nipples.

Consideration should be given to displacing the annulus to an inert fluid like nitrogen or sweet gas prior to conducting operations to keep H₂S as far away as possible from the surface.

Refer to IRP Volume 15 Snubbing Operations for a comprehensive list of approved snubbing procedures.

2.8.8 SAFETY EQUIPMENT

IRP H₂S monitors shall have sensors located at the:

- basket
- pipe insertion point
- ground level around the Safety BOPs
- accumulator vent

Self Contained Breathing Apparatus (SCBA) or Supplied Air Breathing Apparatus (SABA) must be worn on the floor and in the snubbing basket at the beginning of a snubbing or stripping operation. Once it has been determined that the environment is safe and the equipment is working properly the SCBA or SABA can be removed. Egress air units must be available for all SABA. All respiratory masks must be fit tested prior to use.

Explosion proof radio communication must be capable of communicating with the supervisor at ground level with or without a mask being worn.

The maximum duration all members of the crew will be allowed to continuously work while masked up is two hours. After this
time the crew member(s) must take a break in order to prepare themselves for the physical and mental stresses of working while masked up on the next shift.
APPENDIX A.

Figure 1. Stack Configuration 1
Figure 2. Stack Configuration 2
Figure 3. Stack Configuration 3
List of References


2. API, Specification for Wellhead and Christmas Tree Equipment, Latest Revision, Spec. 6A, Dallas, Texas.
2.9 COILED TUBING OPERATIONS

2.9.1 SCOPE

2.9.1.1
This IRP chapter has been developed under the auspices of the Drilling and Completions Committee (DACC). 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 Coiled Tubing Operations during routine completion and servicing conditions on Critical Sour Wells.

2.9.1.2
This IRP is part of a series. For the overall intent of, and as a general reference to the whole series, please refer to IRP 2.0. The recommendations contained in this IRP provide operators with industry-endorsed advice. These recommendations are also intended to be applied in association with all existing government regulations as well as the other IRPs. While strict legal enforcement of good practices is not desired or possible, the BPWSC believes that such practices place considerable onus on the legally responsible party to comply or otherwise provide a technically equivalent or better solution.

2.9.1.3
In cases of inconsistency or conflict between any of the recommended practices contained in this IRP and applicable legislative requirements, the legislative requirements shall prevail.

2.9.1.4
Throughout this document, IRP statements are identified by bold type and include the words “shall” or “must”. Additional best practice statements are not highlighted and contain the words “should” or “recommended”.

2.9.2 PRE RIG-UP

IRP Prior to moving any Coiled Tubing equipment onto the location, the following items must be addressed:

The Operating Company and Service Company will review the Equipment Service Log prior to rigging up and ensure:

- The Coil Tubing to be used on the job has sufficient life to safely complete the job with reasonable contingency.
• The Bench Test and servicing of the BOP System has been performed as per IRP 2.9.5.1
• The Annual Inspection has been completed as per IRP 2.9.5.2
• The Accumulator specifications are available and accumulator sizing calculations have been performed as per 2.9.7.3
• All equipment including the Coiled Tubing and BOP System must be checked for compatibility with the formation fluids and treating fluids.

The Operating Company Representative will indoctrinate the Service Company Representatives prior to moving onto the location. Items to be reviewed will include general safety issues, identifying any hazards on location (rat holes, high pressure piping, etc), muster stations and egress routes.

The Operating Company and Service Company will review the well parameters including:

• Pressures
• Gas composition (especially H\textsubscript{2}S and CO\textsubscript{2} concentrations)
• Salinity of produced water
• Hydrate formation
• Condensate
• Sulphur scales
• Iron sulfide
• NORM (naturally occurring radioactive material)
• Other scales
• Wax
• Asphaltenes
• Wind direction

The Operating Company and Service Company will review proposed equipment layout and spacing requirements.
2.9.3 Rig-Up

IRP A safety/operations meeting must be held with the operators representative(s), coiled tubing crew, and all personnel on the lease to discuss pressure testing, the detailed operations to be performed, delegation of responsibilities, emergency plans and other appropriate considerations.

All hydraulic lines, testing lines and kill lines must be organized and kept tidy so they don’t interfere with an emergency evacuation of the area.

All equipment attached to the wellhead must be adequately supported to limit lateral movement.

NOTE: IRP 2.12, Safety, for detailed matters to be addressed during the safety/operations meeting.

Each coiled tubing operation should be evaluated for potential lateral movement of the equipment rigged onto the wellhead. Injector height, equipment weight and wind conditions should be considered. Guy lines should be installed to rig anchors or a secure anchor point such as portable wellhead cement barricades or pipeline swamp weights.

2.9.4 Pressure Tests

IRP The Coiled Tubing BOP Stack must be pressure tested on a test stump immediately prior to every job to ensure it is operating correctly.

Each component of the BOP Stack must be pressure tested on the test stump as follows:

- A low-pressure test of 1 400 kPa must be conducted on each ram preventer for 10 minutes. This test is to be conducted first.

- A high-pressure test must be conducted on each ram preventer for 10 minutes. The pressure required shall be the wellhead pressure rating or 1.3 times the estimated maximum potential SITHP whichever is the lesser.

- The annular preventer must be pressure tested for 10 minutes to the wellhead pressure rating or 1.3 times the estimated maximum potential SITHP whichever is the lesser.
With the Coiled Tubing BOP Stack & Auxiliary Equipment installed on the wellhead, The BOP System must be pressure tested as follows:

- A low-pressure test of 1,400 kPa must be conducted on each ram preventer for 10 minutes. This test is to be conducted first.

- A high-pressure test must be conducted on each ram preventer for 10 minutes. The pressure required shall be the wellhead pressure rating or 1.3 times the estimated maximum potential SITHP whichever is the lesser.

- The annular preventer must be pressure tested for 10 minutes to the wellhead pressure rating or 1.3 times the estimated maximum potential SITHP whichever is the lesser.

- The stuffing box assembly must be pressure tested for 10 minutes to the wellhead pressure rating or 1.3 times the estimated maximum potential SITHP whichever is the lesser.

The following components of the BOP system shall be pressure tested for 10 minutes to the wellhead pressure rating or 1.3 times the estimated maximum potential SITHP whichever is the lesser. These components must be tested individually. Adjustable chokes do not require testing.

- the connection between the BOP stack and the wellhead
- auxiliary equipment including lubricators & pressure windows
- the bleed-off and kill lines
- all valves in the bleed-off manifold (if applicable)
- reel isolation valve
- rotary swivel
- coiled tubing
- downhole equipment composing a part of the coiled tubing above the check valves

- For a satisfactory pressure test using a low viscosity non-flammable fluid, all tests must maintain a stabilized pressure of at least 90 percent of the test pressure over a 10-minute interval.
For a satisfactory pressure test using Nitrogen, not more than 5% of the value of the test pressure is recorded to have leaked off during the test period. If more than 5% has leaked off then the length of the test must be increased to determine the nature of the pressure decline.

- Sour produced fluid is not an acceptable testing fluid.
- The Check Valves shall be back pressure tested to 7000 kPa prior to running in the hole.

**NOTE:** SITHP = Shut in tubing head pressure. On wells where the maximum potential SITHP is not well established through past operations, it is recommended that pressure tests be conducted to the wellhead pressure rating.

### 2.9.5 Inspection Tests

#### 2.9.5.1 Bench Tests

**IRP** The BOP System will be bench tested and serviced no more than one month prior to service on a critical sour well and after redressing. The procedure/results must be recorded in the equipment log.

**NOTE:** An example of an acceptable procedure is:

- BOP disassembled and inspected defective or worn parts replaced with parts meeting or exceeding original equipment manufacturer specifications.
- Reassemble the BOP components.
- Pressure test BOP stack with all preventers open to the working pressure.
- Install piece of tubing with blanked off end into BOP stack. Close tubing slips and tubing rams.
- Pressure test pipe rams from below to the working pressure, or to the supplier's specifications.
- Close the blind rams and pressure test from between the blind and tubing rams to the working pressure or the supplier's specifications.
- Stamp BOP test date on a tag and attach it to the BOP stack.
- Record test data and maintain on file.
2.9.5.2 Annual Inspections & Tests

Prior to moving the coiled tubing unit on location, metallurgical testing, in accordance with IRP 2.10, Quality Programs, must have been done on the pressure control equipment within the last twelve (12) months.

Inspections must be documented in the equipment service log. A certified person must perform the inspection.

The following equipment should be tested:

- Check Valves
- BOPs, including shear ram blades
- Annular Preventer
- Stuffing box
- Flow Tee with plug valve
- Lubricators
- Pressure Windows

A shear cutoff test must be conducted within the last 6 months. The test shall be conducted according to manufacturer’s specifications.

Pressure control equipment must have a legible stamp or other permanent marking to indicate it is suitable for H₂S service.

Any alterations or repairs requiring welding on pressure control equipment must be metallurgically inspected in accordance with IRP 2.10, “Quality Programs”.

NOTE: Further details of welding procedures are contained in IRP 1.15

The shear cutoff test should be performed on Coiled Tubing of equal or greater outside diameter and wall thickness than that coil that is to be utilized during the operation.

2.9.6 Equipment Service Log

The Equipment Service Log shall include an accurate record of the following:
- all operations conducted with coiled tubing
- fluids types and/or gases pumped
- metres run
- maximum pull on coiled tubing for each job
- the environment the coiled tubing has been run in
- exposure time of the coiled tubing and pressure control equipment to the various environments

A copy of the Equipment Service Log must be maintained (up-to-date) by the coiled tubing operator and kept with the unit.

A coiled tubing operator must have a Pipe Management System. This system will ensure a Quality Program is in place that will utilize the Equipment Service Log to predict when a coiled tubing string must be removed from service on critical sour wells.

2.9.7 EQUIPMENT

2.9.7.1 The BOP System (Pressure Control Equipment)

The pressure rating of all components of the BOP System must meet or exceed the rated working pressure of the wellhead.

The minimum pressure control equipment required for coiled tubing operations on a critical sour well is given below:

- Blind Rams (top)
- Tubing Cutters (top center)
- Tubing Slips (bottom center)
- Tubing Rams (bottom)
- Annular Preventer
- Stuffing box with new element
- Flow tee with 2 high pressure valves (i.e. plug valves)
- The flow tee must be positioned below the BOP Stack
- Tandem Downhole check valves
- Reel isolation valve
• A “kill line” connection, which is not to be used as a circulation line at any time. The connection must be positioned below the Blind Rams. The “kill line” connection shall include a valve and pressure indicator.

2.9.7.2 Auxiliary Pressure Control Equipment

Auxiliary Pressure Control Equipment forms an integral part of the BOP System. This equipment is utilized to pressure deploy more complex coiled tubing bottomhole assemblies into a well. This equipment will include but not be limited to:

• Lubricators
• Pressure Windows

All connections between the bottom of the Coiled Tubing BOP stack and wellhead shall be flanged. Equipment placed above the BOP Stack including the flow tee, lubricator and pressure window connections may be flanged or an engineered connection.

NOTE: Appendix A Illustrates the equipment described above.

2.9.7.3 Accumulator System

The accumulator must have sufficient usable fluid available, at a minimum pressure of 8 400 kPa, to close all BOP rams.

The pre-charge pressure of each accumulator bottle shall be checked and recorded immediately prior to each job.

Accumulator specifications must be available for review on location. The specifications would include:

• accumulator make
• number of bottles
• capacity
• design pressure and operating pressure (upstream of any regulators).

Accumulator sizing calculations must be completed prior to pressure testing the BOPs on location. Records of calculations must accompany the accumulator to the location.
2.9.7.4 Back-up Nitrogen Supply

IRP  Sufficient usable nitrogen must be available, at a minimum pressure of 8 400 kPa, to fully close all BOP rams (including “redundant equipment”).

2.9.7.5 Flush Loop Equipment Configuration

IRP  If the reservoir fluid or a completion/workover fluid is suspected to be incompatible with the BOP Elastomers, provisions shall be made for the injection of a flush fluid across the BOPs to prevent the incompatible fluid from contacting the BOPs Elastomers.

NOTE:  Consideration should be given to using an H₂S Scavenger, or whenever possible, to increase completion fluid pH to a value between 10 and 12, in order to minimize the risk of hydrogen sulphide cracking.

2.9.7.6 Materials

IRP  Metallic and Elastomeric materials shall be utilized in accordance with the specifications set out in Appendix B.

2.9.7.7 Bolting

IRP  External bolting shall be selected in accordance with Appendix B.

2.9.7.8 Certification

IRP  All metallic equipment, which may be exposed to sour effluent, must be manufactured from material meeting the requirements of NACE MR0175, latest edition.¹ This includes coiled tubing string, any downhole accessories, BOP stack, flow tee, stuffing box, isolation valve, flow tee/kill line fittings up to and including high pressure valves.

NOTE:  Identification and stamping procedures, as detailed in NACE MR0175, latest edition¹, should be followed.

The equipment must be traceable to the manufacturer and have material and heat treating records and mill certificates on file. On existing equipment, third party or manufacturer re-certification may be required. Mill certificates will not be required in this case.

2.9.8 Operating Practices

IRP  The coiled tubing unit will not be left unattended while the lubricator/injector head assembly is connected to the wellhead.
A pull test will be performed on the coiled tubing to bottomhole assembly connection prior to running into the well. The intensity of the pull shall be based on the expected operational requirements.

While running in the hole, a differential pressure across the coiled tubing must not exceed the burst or collapse rating of the coiled tubing.

NOTE: Based upon the Coiled Tubing Rig Up Configurations listed in Appendix A:

In the event of a wellhead leak between the Coiled Tubing BOP Stack and the upper master valve, consideration should be given to the following procedures in order to bring the well under control.

- Ensure everyone on location is safe.
- Evaluate if the coiled tubing can be pulled from the hole so the master valve can be closed to bring the well under control.

or

- Evaluate if the well can be safely killed and brought under control.

If the procedures listed above cannot be performed, consideration should be given to the following procedure:

- Identify the depth of the bottom portion of the coiled tubing.
- Pull the bottom of the coiled tubing high enough in the vertical portion of the hole to ensure when the coiled tubing is cut, the top of the coil will fall below the lowest master valve.
- Activate the slip rams, activate the pipe rams
- Ensure tension is pulled into the coil above the slip rams then activate the shear rams and shear the pipe
- Open the pipe rams
- Open the slip rams and allow the pipe to fall below the lower master valve.
- Shut-in the lower master valve and secure the well.
APPENDIX A.

Figure 1. Coiled Tubing BOP Rig Up Schematic (Wellhead On)
Figure 2. Coiled Tubing BOP Rig Up Schematic (Service Rig BOPs On)
Figure 3. Coiled Tubing BOP Rig Up Schematic (Wellhead Off)
## APPENDIX B. COILED TUBING UNITS/EQUIPMENT FOR CRITICAL SOUR WELLS

<table>
<thead>
<tr>
<th>Item</th>
<th>Component</th>
<th>Minimum Recommended Standards</th>
<th>Typical Material Types Used</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.0</td>
<td>Coiled Tubing</td>
<td>NACE MR0175 latest edition</td>
<td>Low Alloy Steel (i.e. ASTM A606 TYPE 4 typical min. Y.S. – 48.3 MPa (70,000psi), maximum hardness – 22 HRC)</td>
<td>Anneal heat treat for seam and HAZ.</td>
</tr>
<tr>
<td>2.0</td>
<td>Valves</td>
<td>NACE MR0175 latest edition</td>
<td>For body components for items under Item 2.0</td>
<td>To be done in the shop, not field.</td>
</tr>
<tr>
<td>2.1</td>
<td>Flow Tee with Kill Connection Valve.</td>
<td>NACE MR0175 latest edition</td>
<td>4130-4140 Steel, 22 HRC max &amp; cast Steel, 22 HRC max.</td>
<td>The Weld procedure and welders must be qualified in accordance with ASME Section IX. In addition the procedure qualification should include microstructure examination and hardness testing. Post weld heat treat (PWHT) of weld is recommended to meet hardness restriction of MR0175, latest edition.</td>
</tr>
</tbody>
</table>
2.2 Downhole check valve (on bottom of coiled tubing)  
NACE MR0175 latest edition  
For internal trim components for all items under Item 2.0.

<table>
<thead>
<tr>
<th>Item</th>
<th>Component</th>
<th>Minimum Recommended Standards</th>
<th>Typical Material Types Used</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>2.3</td>
<td>Isolation Valve</td>
<td>NACE MR0175 latest edition</td>
<td>Stainless steel, carbon steels with chrome or nickel overlay/plating.</td>
<td></td>
</tr>
<tr>
<td>2.4</td>
<td>Plug Valves</td>
<td>NACE MR0175 latest edition</td>
<td>AISI 4130-4140</td>
<td></td>
</tr>
</tbody>
</table>
| 2.5  | CTU BOP STACK  
Blind Rams, Tubing Slips, Tubing Rams  
**Bolting**  
ASTM A-320 L7M Studs  
ASTM A-194 2HM Nuts  
API 6A, PSL II, Temperature Class L  
Temperature Class L | Users should be aware that flange size restrictions apply when using reduced yield strength bolting (i.e. A320 L7M)  
-See Table 49, API 6A, latest edition.  
To avoid de-rating, A453 Grade 660 or CRA bolting must be used. |
|      | **Body** | NACE MR0175 latest edition  
API 6A, PSL II, Temperature Class-L, Fluid Rating D | AISI 4130-4140 | |
<p>|      | <strong>Rams</strong> | MR0175 latest edition | Carbon Steel | |</p>
<table>
<thead>
<tr>
<th>Section</th>
<th>Component</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>3.1</td>
<td>Tubing Slips</td>
<td>See Comments. As noted in NACE MR0175, latest edition, slips are considered to be outside the scope of the document. As such, no materials recommendations are provided.</td>
</tr>
<tr>
<td>3.2</td>
<td>Tubing Shear Blind Ram Blades</td>
<td>See Comments. Typical material used for the blade edge is a case carburized carbon steel, which does not meet NACE MR0175, latest edition, requirements. Consideration should be given to specifying a material meeting NACE MR0175, latest edition, requirements. (i.e. UNS R030035) for the blade edge. Alternatively, operating practices (through use of well servicing fluids) may be employed as a means to control exposure to the sour fluids; however in the case of an unexpected exposure of the shear blade to sour fluids, the component should immediately be removed from service, inspected for any evidence of cracking and reconditioned before re-use.</td>
</tr>
<tr>
<td>4.0</td>
<td>Stuffing Box</td>
<td>NACE MR0175 latest edition. Brass (or other copper base alloys) may undergo accelerated weight loss corrosion in sour oil field environment particularly if oxygen is present.</td>
</tr>
<tr>
<td>5.0</td>
<td>Accessories</td>
<td></td>
</tr>
</tbody>
</table>
### 5.1 Kill Line Fittings –
(from wellhead up to and incl. Valves)

NACE MR0175 latest edition

4030-4140 Steel, 22 HRC Max.

### 5.2 Downhole Accessories

See Note 2

### 5.3 Rotary Joint

See Comments

NACE MR0175, latest edition, materials should be considered. However, if the design of the coiled tubing unit has provisions to isolate the rotary joint from being exposed to the sour fluids, standard materials may be acceptable. Isolation provisions should include tandem downhole check valves and a reel isolation valve between the coiled tubing unit and the tubing reel rotary joint.

**NOTE 1:** The focus of the Technical Resources Subcommittee effort has been to recommend MINIMUM standards for materials to be used for critical sour service. These recommendations are primarily designed to prevent Sulphide Stress Corrosion Cracking because it can result in the “rapid” failure of metals. Similarly (as noted in NACE MR0175 Specification, latest edition) austenitic stainless steel can fail rapidly from chloride stress corrosion cracking in certain environments. However the material selection from resisting the many forms of weight loss corrosion is left as an economic decision to be made by the well operator.

**NOTE 2:** Historically, retrievable equipment that did not meet the previous specifications has been run successfully in critical sour wells. Time of exposure to the environment must be considered.

**NOTE 3:** API 6A refers to the latest revision.
List of References


2.10 Quality Programs for Well Pressure Containing Equipment

2.10.1 Scope

2.10.1.1
Quality program recommended practices have been developed by the Blowout Prevention Well Service Committee (BPWSC), and updated by the IRP Volume 2 Review Committee, with consideration for industry completion and servicing operations, recognizing the need to ensure that the well pressure control or pressure containing equipment utilized is suitable for its intended service. Implementation of a suitable quality program, in particular for well pressure containing equipment not manufactured in compliance with an applicable API specification and API Spec Q1 Quality program1, is recommended.

2.10.1.2.
This IRP is part of a series. For the overall intent of, and as a general reference to the whole series, please refer to IRP 2.0. The recommendations contained in this IRP provide operators with industry endorsed advice, and are intended to be applied in association with all existing regulations as well as the other IRPs. While strict legal enforcement of good practices is not desired or possible, such practices place considerable onus on the legally responsible party to comply or otherwise provide a technically equivalent or better solution.

2.10.1.3
Throughout this section IRPs are highlighted in bold type and the word “shall” or “must” is used. Additional best practices are not highlighted and contain the words “should” or “recommended”.

2.10.2 Quality Assurance Programs

IRP Well pressure control equipment utilized for critical sour well completing and servicing operations shall be manufactured and maintained under a quality program to ensure conformance with the design specifications including suitability for sour service. The design specifications that have been outlined in this IRP are current at time of printing, but the user is reminded to check for updates and follow the latest specifications. It is the responsibility of the well operator and service provider to ensure that any well pressure containing equipment conforms to this IRP.
2.10.2.1 API Well Pressure Containing Equipment Manufacturing

IRP Well pressure containing equipment utilized in critical sour wells made to API specifications shall be manufactured by an API licensed manufacturer. The equipment shall conform to all requirements of the applicable API specification and the manufacturer’s written procedures in accordance with the manufacturer’s approved Quality Program. Technical quality requirements beyond the scope of and/or which exceed the technical/quality requirements of the applicable API specification, shall be per manufacturer’s written procedures. API Spec Q1, Specification for Quality Programs and ISO 9001 detail all aspects of quality programs.

2.10.2.2 Non-API Well Pressure Containing Equipment Manufacturing

2.10.2.2.1 IRP

Well pressure containing equipment utilized in critical sour wells not requiring compliance to API specifications shall be manufactured by a company that has a quality program that addresses the following areas:

- procurement control and traceability
- incoming inspection
- calibration of measurement and testing equipment
- handling, storage and shipping procedures
- quality records
- personnel qualifications
- inspection plan
- manufacturer’s mark
- size and rated working pressure

2.10.2.2.2 IRP

Well pressure containing equipment utilized in critical sour wells not requiring compliance to API specifications shall be identified as such in accordance with manufacturer’s written procedures.
2.10.2.3 Shop Servicing and Repairs

**IRP** Shop servicing and repairs shall be done by either an API licensed manufacturer or a company that meets the requirements of Section 2.10.2.2.

**NOTE:**

a) Repair/service means to clean, replacement of components, and/or reworking of any API specified dimension within the tolerances implicated on the applicable API specification.

b) Re-manufacture refers to rework of OEM (Original Equipment Manufacturer) specified dimension and/or welding. Re-manufacturing should only be done by OEM to ensure the proper operation of re-manufactured equipment.

2.10.3 Quality Control Measures

2.10.3.1 Non-API Well Pressure Containing Equipment

**IRP** The minimum quality control measures set out in Appendix A shall be used to ensure the well pressure containing equipment is suitable for critical sour well operations.

2.10.3.2 Materials Evaluation Methods

Appendix B lists destructive and non-destructive methods for the evaluation of materials for critical sour well operations.
## APPENDIX A.

### Minimum Quality Control Measures for Non-API Well Pressure Containing Equipment

<table>
<thead>
<tr>
<th>Method</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mechanical tests</td>
<td>Tests commonly run are tensile, hardness</td>
</tr>
<tr>
<td>Non-destructive examination</td>
<td>Commonly used methods are ultrasonics, magnetic particle, dye penetration, visual</td>
</tr>
<tr>
<td>Dimensional verification</td>
<td>Must be in conformance with design specifications</td>
</tr>
<tr>
<td>Chemistry verification</td>
<td>Must be in conformance with design specifications</td>
</tr>
<tr>
<td>Traceability to end user</td>
<td>Traceability of component from raw material through manufacturing processes to end user</td>
</tr>
<tr>
<td>Wellsite traceability</td>
<td>Component(s) must be marked in such a fashion so that on-site personnel can verify that the component delivered to the well site is suitable for sour service</td>
</tr>
</tbody>
</table>

**NOTE:** Other tests may be required for special applications (i.e. Charpy impact testing for low temperature notch toughness).
APPENDIX B.

Material Evaluation Methods For Critical Sour Well Operations

Non-Destructive Testing

Chemical Analysis (ASTM E751-01)
- Used to establish the hardenability of the material and the likelihood of having hard heat affected weld zones which would be susceptible to SCC.
- Used to determine the material type and its conformance to Tables I, II, and III of NACE MR0175, latest edition.
- Used to confirm compliance with the one percent Nickle content restriction of NACE MR0175, latest edition.

Eddy Current Inspection (ASME Section V, ASTM E309-95)
- Used for the detection of cracks and volumetric defects in tubular products, but variations in test equipment do allow for the inspection of other types of components.

Hardness Testing (ASTM E10-01, E18-02)
- Used to confirm compliance with the hardness restrictions of NACE MR-01-75, latest edition.

Liquid Penetrant Inspection (ASME Section V, ASTM E165-95)
- Used to detect surface defects on non magnetic components, but can be used for magnetic components. Several types are available with widely varying sensitivities, therefore, for the detection of SCC (sulphide corrosion cracking), one of the more sensitive methods should be used.
Magnetic Particle Inspection (ASME Section V, ASTM E709-01)

- Used to detect surface defects and near surface linear discontinuities in magnetic components. For small fine cracking such as SCC, wet fluorescent techniques should be used.

Radiography (ASME Section V, ASTM E1030-00, E1032-01, E94-00)

- Used to evaluate welds and castings for volumetric defects.

Ultrasonic Inspection, (ASME Section V),

- Used to evaluate welds and castings for volumetric defects and linear discontinuities (i.e. cracks).

Destructive Testing

Bend Testing (ASTM A370-01)

- Used to measure a weld's or material's ability to deform under load without cracking or suddenly failing (usually used for weld procedure and welder qualification testing).

Impact Testing (ASTM A370-01)

- Used to establish a relative measure of the material's or weld's resistance to fracture at low temperatures under high and suddenly applied loads.

Tensile Testing (ASTM A370-01)

- Used to establish the yield and tensile strength of a material or weld as well as its ductility and whether it complies with the minimum specified values for that particular grade.
Definition of Terms

Calibration
- Comparison and adjustment to a standard of known accuracy.

Conformance
- Compliance with specified requirements.

Quality
- Conformance to specified requirements.

Quality Assurance
- Those planned, systematic, and preventive actions which are required to ensure that materials, products, or services will meet specified requirements.

Quality Control
- Inspection, test, or examination to ensure that materials, products, or services conform to specified requirements.

Quality Program
- An established documented system to ensure quality.

Stress Corrosion Cracking (SCC)
- Brittle failure by cracking under combined action of tensile stress and corrosion in the presence of water and hydrogen sulfide or chloride.

Well Pressure Containing Equipment
- Well completion and servicing equipment that includes but is not limited to wellheads, BOPs, wireline lubricators, tubing, landing nipples and plugs and downhole packers.
List of References


2.11 GUIDELINES FOR SELECTING ELASTOMERIC SEALS

2.11.1 Scope

The elastomer IRPs have been developed with consideration for well completion and servicing activities and environment recognizing the need for seal integrity under a variety of service conditions.

This IRP is intended to assist well Operators in selecting elastomers used for well pressure seals. However, it should be noted that plastic (e.g. Teflon and Ryton) and metal to metal (e.g. flange gaskets) seals are often preferred because of their greater resistance to attack by produced or injected fluids. Plastic and metal to metal seals are outside the scope of this IRP. Seal design is also outside the scope of this IRP.

IRP 2.11 addresses effects of service and environmental conditions on elastomeric seal material and sets out recommendations for elastomer selection, testing and quality control.

 Throughout this section IRPs are highlighted in bold type and the word “shall” or “must” is used. Additional best practices are not highlighted and contain the words “should” or “recommended”.

2.11.2 Service Conditions

IRP Compatibility of any elastomeric seal with the intended service environment shall be determined when selecting materials and equipment for the completion and/or servicing of a critical sour well. This includes consideration of the effect of any fluid or substance that elastomer seals may be exposed to as well as ambient temperatures at which seals are required to perform.

NOTE: Appendix A provides a basic reference for elastomer selection. Manufacturer supplied performance properties and recommendations should also be used.

2.11.3 Testing and Evaluation

IRP Specific testing of seals based on anticipated field conditions shall be performed if available information is not adequate for the service application.
NOTE: To evaluate the suitability of elastomers and other seal materials, for a particular well, the user should first refer to the equipment manufacturer's recommendations. These recommendations should be based on materials testing and experience. In addition, the end user must be satisfied that information or data on seal materials meets the intended service requirements. A field specific testing program should be considered to verify the manufacturer's recommendations or to determine an elastomer's suitability.

2.11.4 QUALITY CONTROL

IRP The well Operator shall ensure that records identifying the elastomer materials in use for first line well pressure control seals are kept.

NOTE: The first line well pressure control seals include equipment such as BOP elements and wireline lubricator O-rings.

These records are recommended because there are no standard markings on most elastomer seals to indicate the elastomer material.

2.11.5 SUPPORTING INFORMATION

2.11.5.1 Seal Design

Sealing materials normally include elastomers or elastomers in conjunction with plastics. An elastomer is defined as a material that can be stretched repeatedly to at least twice its original length and upon release of stress will return with force to its original length. Plastics, such as Teflon, Ryton or PEEK, are polymers that are stronger and have better chemical resistance than elastomers but do not have the resilience (rebound) properties of elastomers. Plastics are normally used in conjunction with elastomers for anti extrusion back up.

There are many different elastomeric and plastic seal configurations available for well servicing and completion equipment. O-ring, V ring, bonded seals and compression force activated seals are some of the more common seal configurations.

Seal design is generally done by the equipment manufacturer. However, the end user should familiarize themselves with seal designs available and determine the compatibility for the intended service between the seal material and the seal design.
Factors to be considered are:

**Seal Movement** – Differences between static and dynamic seals should be taken into consideration in the design.

**Service Period** - The length of service should be considered when selecting seal materials as often seal material will perform satisfactorily for a short service period but would be unsuitable for extended service periods.

**Seal Maintenance** - This is an important factor in selecting sealing materials. A wellhead seal may be relatively inaccessible and therefore require long-term performance, whereas a wireline lubricator seal can be changed out after each job.

**Changing Service Conditions** - Seal selection should be based on longer-term changes, which may occur in the well's produced fluids such as increasing H₂S or temperature. Also, initiation of secondary or tertiary recovery could have effects on sealing materials.

### 2.11.5.2 Service Conditions

The user should be aware of the various fluids to be handled and their individual or combined effect on sealing materials. These fluids include the anticipated well production fluids and any other fluid encountered during workovers and/or any chemical additives introduced to the well.

Appendix A is an outline of some of the more common oilfield elastomers, including typical properties. The user should also be aware that for a given generic type of elastomer (e.g. nitrile), manufacturers may have different formulations or compounds each with different chemical resistance and temperature ratings.

With regard to seal material selection, two important parameters are temperature (service and ambient) and the fluids to be encountered for the intended application. Pressure will affect seal mechanical design and operating parameters more than it affects the seal material. Rapid depressurization of the system can also cause rupture of the seal material (explosive decompression).

Elastomers and plastics have upper and lower temperature limitations, which are usually published by the seal manufacturer and are available through them or the equipment supplier. Similarly, the general chemical resistance of elastomers at low temperatures may be critical for BOPs or other equipment. Supplementary heating could be required for the BOP element based on equipment manufacturer's guidelines or government regulations¹.
The T5 temperature measured by the ASTM D1053\textsuperscript{2} test or the TR10 plus 5°C temperature measured by the ASTM D1329\textsuperscript{3} test can be used as estimates of a minimum operating temperature for an elastomer. The Glass Transition Temperature (Tg) of the elastomer is also used to help determine the low temperature capability\textsuperscript{4}.

Fluid exposures can cause changes in the seal material. Some of these changes are reversible and others are not. For example, the seal swelling caused by gas or oil permeation may reverse itself once the elastomer is removed from the exposure environment. H\textsubscript{2}S exposure to elastomers can cause additional "cross linking" of the elastomer to occur which results in embrittlement. This change is irreversible.

The aromatic component of mineral oil based fluids that can be present in crude oil, invert emulsion muds, & frac oil\textsuperscript{5}, can swell and weaken some elastomers. Alcohol, such as methanol, causes some elastomers to lose their resilience. Amine based corrosion inhibitors and sulphur solvent chemicals such as dimethyldisulphide (DMDS) are very aggressive to many elastomers.

Negative effects of these chemicals can vary depending on the elastomer, service, and concentration of chemicals. This effect may be difficult to predict and may require specific testing to determine adverse effects.

**2.11.5.3 Testing and Evaluation**

No oilfield industry testing and evaluation standard exists for elastomers used in oilfield equipment and so the manufacturers’ standards are often used. However, API does have specific test requirements for verifying elastomer performance for wellhead and drill through equipment\textsuperscript{6,7}. These tests are based on standard test environments and equipment temperature and pressure ratings.

In addition, NACE TM0187 98 Standard Test Method for Evaluating Elastomeric Materials in Sour Gas Environments\textsuperscript{8} and NACE TM0296-96 Standard Test Method for Evaluating Elastomeric Materials in Sour Liquid Environments\textsuperscript{9} are good examples of generic test procedures and methods.

**2.11.5.4 Quality Control**

Storage and handling should also be included in the quality control program because many elastomers have a shelf-life due to sensitivity to sunlight and humidity.

Inventory control is especially important because most elastomers look alike. Even in the same generic category such as nitrile, small chemical and dimensional variances made by manufacturers will drastically change the elastomer effectiveness for the given application.
Additional technical information on elastomers is available in references\textsuperscript{10,11,12,13,14}. API and ISO are recommended sources of quality control program information\textsuperscript{15,16}.
# Appendix A. Outline of Typical Properties for Common Oilfield Elastomers

<table>
<thead>
<tr>
<th>Generic Category*</th>
<th>ASTM Designation</th>
<th>Hardness Range (Shore A)</th>
<th>H₂S Resistance</th>
<th>Liquid Hydrocarbon Resistance</th>
<th>Temp Rating** (°C)</th>
<th>Common Trade Name Examples</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural Rubber</td>
<td>NR</td>
<td>25-100</td>
<td>Fair</td>
<td>Poor</td>
<td>-60 to 80</td>
<td></td>
<td>Sometimes used for BOP elements, good low temperature properties.</td>
</tr>
<tr>
<td>Polychloroprene</td>
<td>CR</td>
<td>30-95</td>
<td>Fair</td>
<td>Fair</td>
<td>-50 to 90</td>
<td>Neoprene</td>
<td>High swelling in oil, good low temperature properties, better H₂S resistance than NBR.</td>
</tr>
<tr>
<td>Epichlorohydrin</td>
<td>CO</td>
<td>50-85</td>
<td>Fair</td>
<td>Fair</td>
<td>-40 to 150</td>
<td>Hydrin 100, Herclor H</td>
<td>Good low temperature properties. Has limited resistance to methanol.</td>
</tr>
<tr>
<td>Ethylene Propylene Diene</td>
<td>EPDM</td>
<td>65-90</td>
<td>Good</td>
<td>Poor</td>
<td>-50 to 150</td>
<td>Nordel</td>
<td>Good high temperature used mainly for geothermal applications. Excellent water resistance, large swelling in oil (unsuitable for general oilfield).</td>
</tr>
</tbody>
</table>

* Generic Category
** Temp Rating
<table>
<thead>
<tr>
<th>Elastomer Type</th>
<th>Trade Name</th>
<th>Temperature Range</th>
<th>Softness</th>
<th>Resistance</th>
<th>Application Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nitrile</td>
<td>Buna N</td>
<td>-50 to 120</td>
<td>Good</td>
<td>Poor</td>
<td>Most common oilfield elastomer. Used commonly for packer, BOP elements. Low temperature rating can vary. Various levels of acrylonitrile available.</td>
</tr>
<tr>
<td>Hydrogenated Nitrile</td>
<td>HNBR</td>
<td>-50 to 120</td>
<td>Good</td>
<td>Fair</td>
<td>Improved H₂S and amine resistance over standard Nitrile.</td>
</tr>
<tr>
<td>Fluorocarbon</td>
<td>FKM</td>
<td>-30 to 200</td>
<td>Good</td>
<td>Fair</td>
<td>Common oilfield elastomer often replaces NBR for higher temperatures, can harden in amine inhibitors, sulphur solvents. Has limited methanol resistance.</td>
</tr>
<tr>
<td>Tetrafluoroethylene-propylene</td>
<td>TFEP</td>
<td>0 to 200</td>
<td>Good</td>
<td>Fair</td>
<td>Excellent general thermo-chemical resistance, poor mechanical properties below 0°C, moderate swelling in hydrocarbons, better in amine inhibitors than FKM. Mainly downhole applications.</td>
</tr>
<tr>
<td>Perfluoroelastomer</td>
<td>FFKM</td>
<td>65-95</td>
<td>Good</td>
<td>Good</td>
<td>-20 to 230</td>
</tr>
</tbody>
</table>

* There is no intent to limit the choice of elastomers to these materials only.

**Not all elastomer products in a generic category will have the full temperature range given.
List of References


5. IRP Volume 14: Non-Water Based Drilling & Completions Workover Fluids.


11. Definitions of Terms Relating to Rubber, D1566 87a, ASTM, Philadelphia, PA.


2.12 SAFETY

2.12.1 Scope

The Safety IRP was developed by the Blowout Prevention Well Servicing Committee (BPWSC) and revised by the IRP Vol. 2 Revision Committee to address the minimum acceptable standards and practices for safety during completion and servicing of critical sour wells.

IRP 2.12 details safety recommendations for operations in which the wellhead is removed as well as those in which the wellhead remains in place.

This IRP is part of a series. For the overall intent of, and as a general reference to the whole series, please refer to IRP 2.0. The recommendations contained in this IRP provide operators with industry endorsed advice and are intended to be applied in association with all existing provincial and federal regulations and other regulatory requirements, as well as the other IRPs. While strict legal enforcement of good practices is not desired or possible, the Committee believes that such practices place considerable onus on the legally responsible party to comply or otherwise provide a technically equivalent or better solution.

2.12.2 Definitions

2.12.2.1 Ampoules

Devices that contain chemically-impregnated material to indicate a presence of a chemical by a stain or change in colour in the material in the presence of a particular chemical.

2.12.2.2 Manually Operated Remote Ignition Device

A primary ignition system that, in the event of an uncontrolled release of H₂S while completing or servicing a critical sour well, will ignite a well from a safe location through a time-delayed triggering device after all personnel have safely egressed from the well site.

2.12.3 General Safety Requirements

2.12.3.1 Workwear Requirements

A written personal protective equipment policy should be in place. The policy should state the expectations for personal protective equipment to be worn on site. In most jurisdictions, personal protective equipment must meet CSA standards specified in provincial general safety regulations. The pertinent CSA standard is listed. The policy should cover expectations for the wearing of:
Hardhat

- CSA Z94.1-92 or ANSI Z89.1-1986
- Chin straps are required in B.C. if working from a height exceeding 3 metres

Eye Protection

- CSA Z94.3-92
- Policy should state whether or not side shields are required

Foot Protection

- CSA Z195-M92
- Class should be specified, appropriate to hazard

Hearing Protection

- CSA Z94-2
- Class should be specified appropriate to the hazard

Fall Protection Equipment

- Full body harness: CSA Z259.10-M90
- Fall Arresting Safety Belts and Lanyards: CSA Z259.1-1976

Respiratory Protection Equipment

- Refer to Sections 2.12.6.1 and 2.12.7.1

Fire Retardant Outerwear

- Refer to Canadian Standards Board (CGSB) 155.20 ”Workwear for Protection Against Hydrocarbon Flash Fires“ and CGSB 155.21 ”Recommended Practices for the Provision and Use of Workwear for Protection Against Flash Fires; also Canadian Association of Petroleum Producers (CAPP) Publication #1999-0005 ”Consumer Guideline for the Selection of Fire Resistant Workwear for Protection Against Hydrocarbon Flash Fires“.

Innerwear

- Natural fibre clothing is recommended for innerwear
Gloves

- Appropriate for the hazard (e.g., chemical resistant, leather, etc.)

Use of torn, ragged, soiled and/or hydrocarbon soaked clothing is not acceptable.

Reference:

Alberta: General Safety Regulation, Part 5 – Personal Protective Equipment; Noise Regulation
British Columbia: Occupational Health and Safety Regulation, Part 8 - Personal Protective Clothing and Equipment; Part 7, Noise Control; Part 11, Fall Protection
Saskatchewan: Occupational Health and Safety Regulations, Part VII - Personal Protective Equipment; Part VIII, Noise Control and Health Conservation

2.12.3.2 Smoking

An area should be designated as a smoking area. The area chosen should be a safe area which does not pose a hazard of igniting flammable vapours. Once an area is designated, smoking should only be permitted in this area.

2.12.3.3 Facial Hair

Workers who may be required to wear respiratory protective equipment are required to be clean shaven where the facepiece of the equipment seals with the skin of the face.

Reference:

Alberta: General Safety Regulation, Part 5 - Personal protective Equipment
British Columbia: Occupational Health and Safety Regulation, Part 8 - Personal Protective Clothing and Equipment

2.12.3.4 Long Hair

It is recommended that workers' hair be short enough so as to not become a hazard of being caught in equipment or obstructing vision. In cases of workers with longer hair, workers should be encouraged to confine their hair in a manner that will eliminate the aforementioned hazards.

2.12.3.5 Site Access and Egress

Each well site should have a minimum of two personnel egress routes which allow safe escape under any wind conditions should a release occur. Care must be taken when planning the egress route that it will not be downwind or downhill from a release. Each egress route must have a designated safe briefing area.
2.12.3.6 Operations Involving Explosives

During times of operations involving the use of explosives and detonating devices, such as perforating, all transmitters such as H₂S monitors, radios, cell phones, etc. must be shut off from the time that the detonator is removed from its protective casing until the device is down hole a safe distance. Care must be taken to turn any gas detection monitors back on as soon as it is declared safe to do so. In the case of a perforating gun misfire, all transmitters must again be turned off while the gun is lifted out of the hole and until such time as it is declared safe to turn them back on again.

It is recommended that during times when gas detection monitoring transmitters are turned off that personal gas detection monitors be utilized.

Reference:

Alberta: Explosives Safety Regulation

British Columbia: Occupational Health and Safety Regulation, Part 21 –Blasting Operations

2.12.4 Pre-Job Planning

Before commencing any work on critical sour wells, site specific procedures and the Emergency Response Plan should be reviewed in detail. The site specific Emergency Response Plan should be reviewed to ensure that information is updated for the completions and servicing operations.

A pre-job safety meeting should be held before any work commences. Topics that must be covered in pre-job safety meetings are:

1. Scope of Work

2. Site Specific Hazards

   - Well Characteristics (pressure, percent H₂S, etc.)

      The minimum information should include:

      - Shut-in wellhead pressure
      - H₂S and CO₂ concentrations

   - As operations become more complex, additional information should be discussed, such as:

      - Well deliverability (gas, condensate/oil, water)
      - Bottomhole pressure and temperature
• Scales (sulphur, iron sulfide, other scales)
• Wax, asphaltenes
• Hydrates
• Abnormal hole conditions

3. Potentially serious hazards that require special attention

4. Site Specific Policies and Procedures
• Permitting Procedures
• Lock-Out Procedures
• Ground Disturbance (IRP Volume 17 - Ground Disturbance in the Vicinity of Underground Facilities, IRP 16 – Basic Safety Awareness Training)
• Personal Protective Equipment requirements
• Site training requirements (refer to Section 2.15 - Wellsite Personnel Training and Experience)

5. Command Structure and Responsibilities

6. Communications and Security

7. Emergency Procedures

Personnel should be oriented to the Emergency Response Plan and be made aware of the following:
• location of wind monitoring devices (socks or flagging)
• identification of any on-site emergency alarms
• emergency shut-down procedures
• location of site emergency equipment, such as first aid station or kit, fire extinguishers, air packs, etc.
• Note: the operator should ensure safety equipment is routinely serviced and tested by qualified personnel
• evacuation procedures and egress routes
• identification of safe briefing area
• identification of individuals with first aid training
Completing and Servicing Critical Sour Wells

- location of nearest medical treatment facility and method for transporting injured workers

2.12.5 Equipment Recommendations – General

The following recommended equipment is described in order to provide flexibility regarding the choice and application of equipment. In some cases equipment may become a regulated requirement and should comply with those standards.

A distinction has been made to address lower risk operations where the wellhead is intact and an H₂S release cannot reasonably be anticipated. Where the wellhead is removed or where an H₂S release is possible, more extensive safety equipment is required.

In all cases special consideration should be given to cold weather operations and the low temperature operational limits for breathing apparatus exhalation valves, batteries, hoses and other rubber or flexible fittings.

2.12.6 Equipment Recommendations With Wellhead Intact

2.12.6.1 Breathing Apparatus

Breathing apparatus (respiratory protection) must be available on location, and the masks must be fit tested prior to use. There should be a sufficient number to allow one (1) per person for each person directly involved with the operation or immediate emergency response to the operation. A minimum of two units are required for each drilling or service rig in most jurisdictions, however a minimum of four (4) units are required on site for operations in British Columbia.

Breathing apparatus need not be supplied for temporary or non-essential workers, as in the event of an emergency those workers would be immediately evacuated.

The breathing apparatus can be Self Contained Breathing Apparatus (SCBA) or Supplied Air Breathing Apparatus (SABA) providing there are sufficient SCBA for emergency rescue operations.

Self-Contained Breathing Apparatus must comply with the following:

- is of a type that will maintain positive pressure in the facepiece
- has a capacity of at least 30 minutes
- has a low air supply warning (audible recommended)
- is provided with breathing air meeting CSA Standard CANZ180.1-M85
• is fully operational and well maintained
• is approved by the National Institute of Occupational Safety and Health (NIOSH)

A back-up air supply should be available for contingency purposes with all types of breathing apparatus. Effective back-up may take the form of a spare trailer, a compressor located off the wellsite, or a trailer at the local supplier which may be called out. Care should be taken to keep the acquisition time for back-up air as low as possible.

Fifty (50) cubic feet of air is the estimated quantity that the average worker will consume in thirty (30) minutes. It should be noted that the amount of air a worker will use may be impacted by factors such as the physical demands of the task and the fitness of the worker.

Reference:
Alberta:  General Safety Regulation, Part 5 - Personal Protective Equipment
British Columbia:  Occupational Health and Safety Regulation - Part 8, Personal Protective Equipment/Oil and Gas Operations, Section 446

2.12.6.2 Ambient H₂S Monitoring

Monitoring of H₂S is required, and the type of monitoring is dependent on the complexity of the job.

A portable H₂S monitoring device must be present while workers are at the wellsite. The monitor must be capable of detecting H₂S at ten parts per million (10 ppm). The units must be calibrated and tested before use and care should be taken to ensure that they are properly maintained.

Portable electronic or sample tube devices are acceptable. Ampoule type indicators must not be used as a substitute for continuous monitoring.

2.12.6.3 Communications

For contingency purposes each work site should have reliable communications with resources off the worksite.

2.12.6.4 On Site Wind Monitoring

Wind socks or flagging should be located on the work site to indicate wind direction at ground level and aid in establishing site specific egress routes. The location and number of wind socks or flags should be sufficient to allow personnel at the various work stations to easily view the wind direction at all times.
2.12.6.5 Site Access Control

The main entrance to the lease should be marked with appropriate warning signs which indicate:

- access is restricted
- H₂S gas may be present
- any other hazards which are specific to the operation

A record should be kept of all persons entering and exiting the lease area for the purposes of a head count should an emergency situation occur. All visitors should be briefed on emergency procedures upon entering the lease area.

2.12.6.6 Emergency Washing Facilities

Emergency washing facilities must be provided within a work area where a worker’s eyes or skin may be exposed to harmful or corrosive materials or other materials which may burn or irritate.

Reference:
Alberta: First Aid Regulation
British Columbia: Occupational Health and Safety Regulation - Part 5.85 Emergency Washing Facilities

2.12.6.7 Fire Extinguishers

A minimum of four (4) 40-BC extinguishers are required for drilling and service rigs.

Reference:
British Columbia: Occupational Health & Safety Reg’n Part 23-Oil and Gas Operations

2.12.6.8 Emergency Vehicle

A vehicle should be designated as an emergency vehicle to provide emergency egress for the site. This unit must be well maintained, not be used for any purpose which may delay transportation of an injured worker, be capable of transporting at least one worker on a stretcher, provide protection from natural elements and dust and have an effective means of communication.

The emergency vehicle may take various forms depending on the special conditions at the worksite. Special circumstances may require that a helicopter, bus, boat or other means of transportation be available for egress or the transport of injured workers.
EQUIPMENT RECOMMENDATIONS WITH WELLHEAD REMOVED

Breathing Apparatus

Breathing apparatus (respiratory protection) must be available on location, and the mask must be fit tested prior to use. There should be a sufficient number to allow one (1) per person for each person directly involved with the operation or immediate emergency response to the operation. A minimum of two units are required for each drilling or service rig in most jurisdictions, however a minimum of four (4) units are required on site for operations in British Columbia.

Breathing apparatus need not be supplied for temporary or non-essential workers, as in the event of an emergency those workers would be immediately evacuated.

The breathing apparatus can be Self Contained Breathing Apparatus (SCBA) or Supplied Air Breathing Apparatus (SABA) providing there are sufficient SCBA for emergency rescue operations.

Self-Contained Breathing Apparatus must comply with the following:

- is of a type that will maintain positive pressure in the facepiece
- has a capacity of at least 30 minutes
- has a low air supply warning (audible recommended)
- is provided with breathing air meeting CSA Standard CANZ180.1-M85
- is fully operational and well maintained
- is approved by the National Institute of Occupational Safety and Health (NIOSH)

A back-up air supply should be available for contingency purposes with all types of breathing apparatus. Effective back-up may take the form of a spare trailer, a compressor located off the wellsite, or a trailer at the local supplier which may be called out. Care should be taken to keep the acquisition time for back-up air as low as possible.
Fifty (50) cubic feet of air is the estimated quantity that the average worker will consume in thirty (30) minutes. It should be noted that the amount of air a worker will use may be impacted by factors such as the physical demands of the task and the fitness of the worker.

Reference:

Alberta: General Safety Regulation, Part 5 - Personal Protective Equipment

British Columbia: Occupational health and Safety Regulation, Part 8, Personal Protective Equipment/Oil and Gas Operations, Section 446

Saskatchewan: Occupational Health and Safety Regulations, Part VII - Personal Protective Equipment; Oil and Gas Operations, Section 446

2.12.7.2 Supplied Air Breathing Apparatus (SABA)

Where continuous work is performed in an H₂S atmosphere exceeding 10 ppm, SABA should be considered. Additional self contained breathing assemblies should be provided for back-up or for additional worker requirements (refer to Section 2.12.7.1). A well maintained manifold must connect the lines to the on-site cascade air system.

Each SABA unit should include or provide:

- a facepiece and airline connected to a regulator assembly for egress
- a pneumatic quick coupler
- an adequate harness assembly
- sufficient compressed breathing air on-site to supply essential workers with 500 cubic feet per man (5 hour supply)

In addition to the above, an auxiliary supply of respirable air of sufficient quantity to enable the worker to escape from the area in an emergency is required.

A back-up air supply (500 cubic feet per essential worker) should be readily available for contingency purposes. Effective back-up may take the form of a spare trailer, a compressor located off the wellsite, or a trailer at the local supplier which may be called out. Care should be taken to keep the acquisition time for back-up air as low as possible.

2.12.7.3 Ambient H₂S Monitoring System

Portable H₂S monitoring devices, capable of detecting ten parts per million (10 ppm) should be present while workers are at the wellsite.
Continuous monitoring should be considered within the context of the Emergency Response Plan requirements.

When a continuous monitoring system is employed, a qualified technician must be employed to set up and calibrate the equipment. The system must be routinely calibrated and tested by a qualified person.

A suitable continuous H₂S monitoring system should include:

- sensors that are operable a minimum of forty-five (45) metres from the control unit
- a minimum of four (4) channels with weatherproof sensors
- an audible alarm and may include various sound settings
- a visual alarm
- a calibration kit

The H₂S monitoring system should provide alarms as follows:

- low alarm: 10 ppm H₂S
- high alarm: 20 ppm H₂S

The low alarm may be visible and/or audible. The high alarm should be visible and audible.

Remote sensors should provide warning from:

- bell nipple/wellhead
- rig circulation tank
- other hazardous areas around the wellsite

The ceiling occupational exposure limit to H₂S in British Columbia requires breathing apparatus be used if H₂S concentration is greater than 10 ppm. In Alberta, the ceiling limit is 20 ppm. If the H₂S concentration is less than 10 ppm, workers are allowed a maximum exposure of eight (8) hours.

2.12.7.4 Lease Lighting

Adequate lighting should be supplied on-site and be sufficient to allow work to be conducted safely and to eliminate shadows in key work areas.

As there is potential on any job that work may extend to after dark, auxiliary lighting and/or power should be arranged for, particularly in the case where a
service rig is not in use. Keep in mind that when positioning or providing complementary lighting, the existing regulations that pertain to spacing and electrical standards apply.

See also IRP Volume 23 – *Lease Lighting Standards* (under development at time of publication)

Reference:

Alberta: General Safety Regulation

British Columbia: Occupational Health and Safety Regulation - Illumination, Part 4


**2.12.7.5 Communication**

For contingency operations, adequate communications should be provided on-site to communicate with road block locations, security personnel and others within the area around the wellsite to which access is controlled. In addition, reliable communications are required to maintain contact with others outside the controlled zone.

Communications equipment should include:

- dual frequency base stations at the wellsite or security location
- one hand held radio for each emergency road block location on one of the frequencies at the base station
- two intrinsically safe hand held radios for the wellsite
- adequate communications to the outside telephone system

**2.12.7.6 Continuous Mobile Downwind Surveillance Unit**

As part of emergency planning, a continuous downwind monitor should be included as part of Emergency Response Plan procedures.

An adequate mobile surveillance unit would be equipped with:

- a low range H$_2$S analyzer
- a low range SO$_2$ analyzer
- a strip pan recorder
- wind speed and direction indicators
• uninterruptible communications with the wellsite

In the event of a substantial release of H₂S or SO₂, an effective means to track the plume is required to ensure the safety of others in the area. Mobile air monitoring services are available for production testing, flaring operations and blowouts.

Reduced response time or standby arrangements should be made where proximity to major residential or recreational areas presents a risk to the public. Equipment may be required as part of the regulated approval process and should, therefore, comply with specified requirements as determined by the approving regulator.

2.12.7.7 On-Site Wind Monitoring

In addition to wind socks and flagging located at the rig circulation tank and other areas around the wellsite, it is recommended that a unit be located on-site to accurately measure wind speed and wind direction to effectively predict the direction of a gas release and the rate of dissipation.

2.12.7.8 Emergency Warning System

Arrangements should be made to warn residents, workers, sportsmen or other users of the area in the event of an H₂S release.

Several types of systems or equipment may be used to warn local residents or users of the immediate area, should an H₂S release occur. These would include personal visitations, information signs, telephone network, pagers, sirens or other audible devices. Care should be taken when locating audible devices to ensure that maximum coverage is achieved, particularly in heavy timber or low lying areas.

To avoid public confusion, such systems should not conflict with regulator-approved Emergency Response Plans that already exist in the area. Procedures should be established to advise the public of appropriate responses to follow when the system is activated.

2.12.7.9 Site Access Control

Access to the wellsite should be controlled to restrict unauthorized persons from approaching the lease and to warn those entering the area when hazardous H₂S operations are underway.

A record should be kept of all persons entering and exiting the lease area for the purposes of a head count should an emergency situation occur. All visitors should be briefed on emergency procedures before entering the lease area.
Equipment recommended for each access control station includes:

- a portable continuous H$_2$S monitor
- one (1) SCBA and one (1) spare thirty (30) minute cylinder
- one (1) portable road barricade
- one (1) gas detector with low range H$_2$S and SO$_2$ tubes
- one (1) reflective vest
- a means of two way communications with the lease
- a reliable and effective means to record entries and exits from the lease; the system must indicate at any given time the number and names of personnel present at the wellsite
- a checklist for briefing visitors on the Emergency Evacuation Plan; the checklist should be signed by the visitor after orientation and kept on site until the visitor has left the lease.
- a stop sign
- other signs as required
- spare batteries for each battery powered piece of equipment

2.12.7.10 Emergency Washing Facilities

Emergency washing facilities must be provided within a work area where a worker’s eyes or skin may be exposed to harmful or corrosive materials or other materials which may burn or irritate.

Reference:

Alberta: First Aid Regulation

British Columbia: Occupational Health and Safety Regulation, Part 5.85 Emergency Washing Facilities

2.12.7.11 Fire Extinguishers

A minimum of four (4) 40-BC extinguishers are required for drilling and service rigs.

Reference:

British Columbia: Occupational Health and Safety Regulation, Part 23 - Oil and Gas Operations
2.12.7.12 Emergency Vehicle

A vehicle should be designated as an emergency vehicle to provide emergency egress for the site. This unit must be well maintained, not be used for any purpose which may delay transportation of an injured worker, be capable of transporting at least one worker on a stretcher, provide protection from natural elements and dust and have an effective means of communication.

The emergency vehicle may take various forms depending on the special conditions at the worksite. Special circumstances may require that a helicopter, bus, boat or other means of transportation be available for egress or the transport of injured workers.

Reference:
Alberta; First Aid Regulation, High Hazard Work
British Columbia: Occupational Health and Safety Regulation, Part 33 - First Aid Regulation
Saskatchewan: Occupational Health and Safety Regulations, Part VII – Personal Protective Equipment; Oil and Gas Operations, Section 446

2.12.7.3. Other Recommended Equipment

The following equipment is recommended to provide additional support, especially for emergency situations:

- a manually operated remote ignition device; flares should only be considered as a secondary ignition system
- revival equipment; may include items such as inhalators, ventilators or resuscitators (required for snubbing operations in B.C.)
- explosion meter (LEL monitor)
- rescue ropes and harnesses with shoulder straps

Care should be taken when giving consideration to the use of ignition or revival equipment. They both require unique techniques and should only be operated by properly approved and trained personnel.

Reference:
Alberta Energy and Utilities Board: Interim Directive 90-1, Completion and Servicing of Sour Wells
British Columbia: Occupational Health and Safety Regulation, Part 23 - Oil and Gas and Part 33 - Occupational First Aid
2.12.7.14 Training Facility

As training and site orientations may be required at the well, a suitable facility or location must be designated to allow effective training under any potential weather or environmental condition.
List of References


   Queen's printer
   Calgary: 403) 297-6251
   Edmonton: (780) 427-4952

5. British Columbia Occupational Health and Safety Legislation
   Queen's Printer: (604) 945-3446

6. Saskatchewan Occupational Health and Safety Legislation
   Queen's Printer: (306) 787-6894

7. Manitoba Occupational Health and Safety Legislation
   Workplace Safety and Health: (204) 945-3446

8. Illuminating Engineering Society of North America (IES Handbook)
   On-line: [www.iesna.org](http://www.iesna.org)
   IESNA: (212) 248-5000
2.13 Suspension Practices

2.13.1 Scope

Objectives
The suspension practices IRPs have been developed by the Blowout Prevention Well Servicing Committee (BPWSC) and revised by the IRP 2 Review Committee, to ensure the safe suspension of inactive Critical Sour Wells. IRP 2.13 addresses suspension methods for both newly drilled wells and completed wells to preserve the integrity of the wellbore and to maintain downhole equipment, tubular goods, and wellhead equipment to permit safe re-entry of a suspended critical sour well.

Inactive Wells
The suspension practices contained in this IRP are applicable to inactive cased wells. Wells are "inactive" if operations have been suspended for a period greater than six consecutive months and where the wellbore is to be maintained to commence or resume production/injection at a later date. Suspension begins the day after the last operations on the well (i.e. initial suspension date).

Sour Service
"Sour service" means manufactured from metallic resistant to SSC in accordance with NACE Standard MR0175, latest edition. For advice on non-metallic (resilient seals, etc.) refer to IRP 2.11(8).

Application
This IRP is part of a series. For the overall intent of, and as a general reference to the whole series, please refer to IRP 2.0. The recommendations contained in this IRP provide operators with industry-endorsed advice, and are intended to be applied in association with all existing government regulations as well as the other IRPs. While strict legal enforcement of good practices is not desired or possible, the BPWSC believes that such practices place considerable onus on the legally responsible party to comply or otherwise provide a technically equivalent or better solution.

Prevailing Legislation
In cases of inconsistency or conflict between any of the recommended practices contained in this IRP and applicable legislative requirements, the legislative requirements shall prevail.
2.13.2 Downhole Equipment

2.13.2.1 Wells Not Complete

IRP  If a liner has been run, then the liner top shall be pressure tested for leaks (see 2.13.5). If the liner top leaks, it must be isolated with a bridge plug set above the liner top and capped with a cement plug.

IRP  For all liner tops that do not leak and for all open hole-completions, a retrievable bridge plug shall be set within 100 m of the liner top or open hole, and pressure tested for leaks (refer to 2.13.5). As an alternative, a packer with a plug in place can be run.

2.13.2.2 Completed Wells

IRP  A bridge plug capped with 8 linear metres of cement shall be used to suspend critical sour wells which have been completed and have had the tubing removed. The bridge plug shall be pressure tested to 7000 kPa or to the maximum anticipated pressure differential, whichever is greater, prior to capping with cement.

IRP  An acceptable alternative suspension method for wells with a packer and tubing is to install a tubing plug in a landing nipple located close to the perforated interval preferably below the sour service packer. For gas lift wells the tubing plug must be installed below the lower most gas lift valve. The tubing plug shall be tested to 7000 kPa or to the maximum anticipated differential pressure, whichever is greater.

IRP  The wellbore (casing or tubing and annulus) shall be displaced to inhibited fluid.

NOTE:  A bridge plug or packer will prevent the casing and the wellhead from contacting sour formation fluids. Also, since killing the well without tubing could be very difficult, the bridge plug or packer would keep pressure off the wellbore above the bridge plug/packer and make well entry easier.

The tubing plug in the bottom of the packer-tubing assembly is to provide a first-line defense against sour formation fluids contacting the tubing and the wellhead. The inhibited fluid should provide pressure back up for the packer and plug, as well as provide inhibition against corrosion.
Having the plug below the lowermost gas lift valve provides a seal to prevent sour formation fluids from contacting the lift mandrels and casing.

2.13.3 Wellhead

2.13.1.1 Complete Wells

IRP All suspended critical sour wells, perforated or not, must be equipped with sour service wellhead/Christmas tree with an API maximum working pressure rating (MWPR) equal to or greater than formation pressure. The primary and secondary seals which seal around the production casing must have been activated and tested to at least 1.1 times the maximum anticipated shut-in tubing head pressure (SITHP). The pressure test shall not exceed collapse resistance of the casing.

IRP The outside flange/connection on all wellhead and Christmas tree assemblies shall be equipped with components having the same working pressure as the wellhead to allow pressure measurement on all tubing strings. Flanged and/or studded spool outlets shall be equipped with a blind and/or companion flange, tapped, and a needle valve installed of a working pressure rating equal to the wellhead/Christmas tree components (see Appendix A, Figure 1). Threaded outlets shall be equipped with a bull plug, tapped, and a needle valve installed. The needle valves shall also be plugged.

Appendix A, Figure 1 illustrates the recommended configuration.

2.13.1.2 Newly-Drilled Wells

IRP A capping assembly can be used as a temporary wellhead for newly-drilled non-perforated wells awaiting completion. The equipment must be sour service, of an API MWPR equal to or greater than the formation pressure and equipped with secondary seals, which must be activated, and pressure tested upon installation.

Refer to Appendix A, Figure 2 for capping assembly.

2.13.4 Wellbore Fluids

IRP Wells shall be filled with a corrosion-inhibited fluid topped with a non-freezing fluid such as diesel fuel.
The fluid levels should be maintained during inspections. If possible, fluid levels in the surface production casing annulus should be maintained to prevent external corrosion of the production casing at the fluid-air interface.

**NOTE:** The inhibited fluid provides pressure backup as well as protection against corrosion.

### 2.13.5 Casing and Wellhead Pressure Tests

#### 2.13.5.1 Newly Drilled Wells

**IRP** Newly-drilled critical sour wells with the formation isolated behind production casing or liner, or where the productive interval (open hole) will be isolated with a bridge plug, the production casing shall be tested to at least 1.1 times the maximum anticipated SITHP. Where a downhole bridge plug is installed to isolate the productive interval or liner top, it shall be tested to at least 7000 kPa or the maximum anticipated differential pressure, whichever is greater.

**IRP** The entire wellhead/Christmas tree or capping assembly must also be tested to at least 1.1 times the maximum anticipated SITHP after installation.

The wellhead/Christmas tree or capping assembly for the well will be hydrostatically tested in the shop to the appropriate test pressure specified in API Specification 6A\(^1\) prior to shipment to the lease. Provided the wellhead/Christmas tree or capping assembly is transported and installed in one piece (at least from the tubing hanger spool to the top master valve inclusive), no further testing shall be needed for suspension other than the previously specified test of primary and secondary seals around the production casing. This only applies to wells which are temporarily suspended pending completion within a six-month period.

**IRP** If a well is to be left suspended for a longer period of time than six months, the entire wellhead/Christmas tree or capping assembly above the production casing packoff assembly must be tested to at least 1.1 times the maximum anticipated SITHP after installation.

IRP 2.1 details a procedure to determine the SITHP.
2.13.5.2 Perforated and Completed Wells

IRP  For critical sour wells suspended with tubing, tubing plug and packer, the upper Christmas tree assembly (i.e. above the tubing hanger) and the production casing by tubing annulus shall be tested to a least 1.1 times the SITHP prior to suspension.

IRP  For critical sour wells suspended with a bridge plug capped with cement, the entire wellhead/Christmas tree assembly and production casing shall be tested to at least 1.1 times the maximum anticipated SITHP.

IRP  Following the initial suspended-well pressure test, annual packer isolation testing is to be conducted. Suspended critical sour wells, which have surface pressure indicating a downhole leak or that fail annual packer isolation testing must be repaired within 30 days of failure determination date.

Where cathodic protection has been installed, it should be regularly monitored.

2.13.6 Inspection Frequency

IRP  Suspended critical sour wells must have an inspection at least once per year, using the checklist contained in Appendix B. Wellhead and annulus pressures shall be recorded, bled to zero, and rate of pressure increase recorded over a 24-hour period (longer if necessary). Samples of any produced hydrocarbons will be obtained and analyzed. Any recorded pressure data and the result of oil/gas analysis must be reported to the regulatory authority.

The licensee shall retain completed inspection checklists on file.

NOTE:  Bleeding pressures to zero and monitoring the 24-hour pressure build-up is part of annual packer isolation testing. If the annual test is completed as required this would not need to be done during the inspection.
2.13.7 Security

IRP All wellhead valves are to be chained and locked.

IRP All wellheads must be clearly marked and visible in all seasons. An acceptable means of marking would include painting in a colour that stands out from the background.

IRP Physical barriers that are clearly visible shall be constructed around wellheads of critical sour wells to prevent damage from accidental vehicle contact.

These barriers should be readily removable to accommodate servicing operations. Concrete barriers are recommended but another example of an acceptable barrier would be a fence constructed from steel tubing anchored in large diameter tubing sleeves cemented in the ground around the wellhead.

IRP Access roads to well sites shall, where possible, contain locked gates or physical barriers restricting entry.

IRP A clearly visible cautionary sign shall be located on the gate restricting access. The sign shall include "Critical Sour Well", well name including LSD (legal subdivision), and a 24-hour emergency phone number consistent with the Emergency Response Plan (licensee or operator as appropriate). Farming operations are not permitted within a 25 m radius of the wellhead.

NOTE: The sensitivity of the well must be considered when addressing whether or not additional security is required. Factors affecting well sensitivity are the population density in the vicinity of the well and the presence of public facilities or transportation corridors in the vicinity of the well.

Additional wellhead protection measures which may be considered are: designing lease roads so that normal traffic does not pass near the wellhead; constructing berms or ditches to separate the lease roadway from the wellhead; use of a wellhead cage; complete fencing around the perimeter of the lease.
APPENDIX A. WELL SUSPENSION SCHEMATICS

Figure 1. Recommended Wellhead/Christmas Tree Configuration for Suspended Critical Sour Wells
Figure 2. Capping Assembly for Suspended Critical Sour Wells
**APPENDIX B.**

**Figure 1. Inspection Checklist For Suspended Wells/Suspension Guidelines For Inactive Wells**

<table>
<thead>
<tr>
<th>Lease Location:</th>
<th>Inspected by:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Date:</td>
<td></td>
</tr>
</tbody>
</table>

**Lease**

1. Lease identification sign posted.
2. Lease properly levelled.
4. Lease diked.
5. Vegetation under control (wellhead clearly visible).
6. Fence installed, if required.
7. No oil on lease.
8. No oil in cellar.
9. No saltwater on lease.
10. Access road in good condition.
11. Cautionary sign (Class "E" wells).

**Wellhead**

1. All openings capped, bull plugged, or blind flanged.
2. No wellhead leaks.
3. No gas bubbles around wellhead.
4. Surface casing vent properly installed and open.
5. No vent flow.
6. Valves functional (open/close). Grease and service as required to maintain functionality.
7. Valve handles chained and locked, or as an alternative, valve handles removed.
8. Casing pressures:
   - Surface casing
   - Intermediate casing
   - Production casing
9. Tubing Pressure:
10. Fluid levels:
   - Surface casing
   - Intermediate casing
   - Tubing
11. Integrity tests:
   - Wellhead
   - Casing
12. Gate on road (Class "E" wells).

12. Packer isolation test to 1400 kPa for wells completed with packers.

List of References


Further Resources

Alberta Energy and Utilities Board, Interim Directive 90-01, Completion and Servicing of Sour Wells, Calgary, Alberta.


2.14 WELLSITE PERSONNEL TRAINING AND EXPERIENCE

2.14.1 SCOPE

The Wellsite Personnel Training and Experience IRPs have been developed to provide qualification guidelines in regard to training and experience levels for personnel conducting servicing operations on critical sour wells.

Recommendations address safety knowledge, especially as it applies to working with \( \text{H}_2\text{S} \) gas, and skills required under emergency conditions relating to well control situations. The recommended experience levels are intended to provide guidelines as to a minimum working knowledge required to perform each operation in a safe, competent manner.

The tasks and the corresponding training and experience level requirements are essentially the same for individual responsibility levels regardless of having the “Christmas Tree” installed on the well or not. To this end, the recommendations presented below are for any and all Servicing or Completion work being conducted on Critical Sour wells.

It is assumed that support personnel (i.e. Completion Engineers and Superintendents) are familiar with and have taken into account IRPs for Critical Sour Well Servicing. The various IRPs should be considered during the planning of the operations and in designing the materials that will be used in the work on the Critical Sour Well. This support should continue during the actual operations at the wellsite.

Wellsite personnel shall be responsible for checking the suitability of materials and equipment used in the operations, but only to the extent that they are identifiable and can be asserted to meet specifications.

The Wellsite Personnel IRPs have been extended to address Training and Experience Qualifications and Requirements for Employer Supervisor’s and their crews for conducting Servicing and Completion Operations on Critical Sour Wells.

The roles and responsibilities for the Operator's Wellsite Supervisor as well as the Rig Manager and rig crews are outlined. In addition, experience levels and training/certification requirements for employer supervisors and crews are summarized. IRP Volume 7 - Standards for Wellsite Supervision of Drilling, Completions & Workovers has been developed to address Wellsite Supervisor Competency. This document outlines specific recommendations for site supervisors and should be referenced when reviewing personnel requirements as recommended in this section. IRP 7 recommends requirements for wellsight
supervisors; however, this section also sets out specific recommendations for the experience levels of the wellsite supervisors as well as other on-site employer supervisors and workers involved in servicing and completion operations on Critical Sour Wells.

Training recommended in this section are consistent with that recommended by IRP 7. This section also makes recommendations for training and experience guidelines for the Rig Manager, Driller, Service Rig crews, Employer Supervisors, Service Crews and H₂S Safety Personnel.

The training requirements for the Rig Manager have been updated to correspond with the requirements recommended for the wellsite supervisor. The training courses required in IRP 7 are outlined in Section 7.6 and are presented there with a brief description of the content of each course.

### 2.14.2 General Requirements

The certification addressed under this section is required for any well servicing operation carried out at a critical sour well.

#### 2.14.2.1 H₂S Certification

**IRP** Any person directly involved in wellsite operations must have a valid H₂S Alive* certificate.

**NOTE:** Any personnel that do not have a direct involvement in the operations on the well and are on location for a short period of time are exempt, provided they are made aware of the hazards of H₂S. Their presence on the wellsite should be kept to a minimum and they must be protected (by isolation if possible) from possible exposure to H₂S.

* Refer to section 2.14.6 Certification and Training Course References.

### 2.14.3 Responsibilities

#### 2.14.3.1 Operator’s Representative

**IRP** The Operator must delegate a Primary Wellsite Supervisor as having overall control in the chain of command.

This delegation should be formalized and reviewed with on-site personnel on an ongoing basis to assure that all new personnel are familiar with the chain of command. Refer to IRP 7 for recommendations regarding assignment of the wellsite supervisor assignments by the Prime Contractor.
The Primary Wellsite Supervisor has the overall responsibility to the operating company or the Prime Contractor for the well and for compliance with all regulations relating to the operations being conducted on the well.

The supervisor must establish a chain of command and a line of communication at the wellsite.

The day-to-day operations on a lease are a shared responsibility between the Contractor and Operator’s representatives. The ultimate responsibility for supervision of the well operation is assigned by the Operator to the Operator’s representative.

**2.14.3.2 Rig Contractor’s Representative/Employer Supervisors**

The reporting structure shall be configured to provide for a single chain of command from the Operator to the Operator’s Representative to the Rig Contractor’s Representative and/or Employer Supervisors.

The Rig Contractor’s representative is responsible to the Operator’s representative for the operation of the rig during the Servicing or Completion operations on the well to provide for a single chain of command for the well operation. The Rig Contractor representative is responsible to his company for the rig equipment and crew, and for compliance with all regulations relating to the operation of the rig.

The Employer Supervisors are responsible to the Operators Representative for the operation of the equipment and services they provide as well as the direction and safety of the crews under their supervision. The Employer Supervisors are responsible for compliance with all regulations relating to the operation of their equipment.

**2.14.4 Availability**

**2.14.4.1 Wellsite Supervisors (Operator’s Representatives)**

IRP A 24 hour operation requires two supervisors, each working 12-hour shift on site.

IRP The Wellsite Supervisor shall be onsite at all times the well operations are active and the critical zone has potential to be open.

In the event of an accident or illness whereby the Primary Wellsite Supervisor is unable to continue with his tasks, an alternate person that
can be in contact with the operations and provide direction to the onsite personnel must be designated.

This delegation should be formalized and reviewed with on-site personnel on an ongoing basis to assure that all new personnel are familiar with the chain of command at the wellsite.

2.14.4.2 Rig Manager (Rig Contractor’s Representative)

The Rig Manager is a key person in the chain of command for Critical Sour Servicing and Completion operations. As such, they must be readily available to direct the operations of the Service Rig Crew. Whenever possible, the Rig Manager should be on location when operations are active and the Critical Zone has potential of being open. When the Rig Manager must be off-site, they should only be absent when operations are of a more routine nature and well control is not a problem.

If the Rig Manager is required to be off-site, he must designate an alternate person to assume his responsibility in his absence.

2.14.4.3 Rig Crew

A minimum 4-man rig crew for each shift shall be maintained while in the critical zone.

In addition to the Rig Manager, the crew would consist of the driller, derrick hand, and two floorhands on each shift.

2.14.4.4 H₂S Safety Service Supervision

A 24-hour operation requires two Safety Supervisors, each working 12-hour shift on site.

2.14.4.5 Employer Personnel (Service Company Personnel Other Than Rig Operations Personnel)

Service Company crews (such as Stimulation crews, Wireline crews and Testing crews) should be configured so that adequate personnel are on location at all times in order to conduct the job in a safe and competent manner. In the event that the job runs over a long duration, adequate personnel must be planned for (in advance) to allow the crew members sufficient time to rest. Adequate rest time for service crews must also take into account the travel time to get equipment to location and the set-up time for the job.
2.14.5 Competency

2.14.5.1 Operating Company Office Supervisors

The demands placed on office supervisors (e.g. Superintendents) of a critical sour workover or completion operation is very high due to the inherent complex nature of the operation, the increased risk factor, and the public impact of the operation.

Office Supervisors must therefore have the technical, organizational and operational competence to meet these demands accordingly.

IRP 7 section 7.6.3 details training requirement recommendations for the person directing the Wellsite Supervisor (the Operator’s Superintendent or Engineer for example).

2.14.5.2 Primary Wellsite Supervisor

IRP The primary wellsite supervisor must be competent in the application of existing IRPs and Emergency Response Planning.

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

- 5 years Wellsite Supervisory experience (or 3 years Completion and Workover technical design plus 2 years Wellsite Supervisory experience).
- Supervised a minimum of 5 Sour Workover or Completion operations while operations were being conducted in the sour zone.

The complexity of a well generally increases with depth, therefore, the primary Wellsite Supervisor's previous Sour Well experience must have been on wells of similar complexity and depth when compared to the Critical Sour Completion or Servicing Operation they will be supervising.

IRP The Primary Wellsite Supervisor training/certification requirements are:

- Well Service BOP*
- \( \text{H}_2\text{S} \) Alive*
- Standard First Aid*
- WHMIS*
- TDG*
• Safety Management and Regulatory Awareness For Wellsite Supervision*

• Detection and Control of Flammable Substances*

* Required by IRP 7.0 for Completion and Workover Supervisors

The following training is not a requirement but it is recommended for the Primary Wellsite Supervisor:

• Confined Space Entry (Pre-Entry portion only)

• Fall Protection

The supervisor must be prepared to substantiate their work history. Time forward work should be maintained in a history log and should be verifiable by the operating company office supervisor.

2.14.5.3 Second Wellsite Supervisor

IRP  The Second Wellsite Supervisor must have the following minimum experience levels:

• 3 years Wellsite Supervisory experience (Operator or Rig Contractor) or (2 years Completion and Workover technical design plus 1 year Wellsite Supervisory experience).

• Must have supervised a minimum of 2 Sour Workover or Completion operations of similar depth and complexity while operations were being conducted in the sour zone.

IRP  The Second Wellsite Supervisor training/certification requirements are:

• Well Service BOP*

• H₂S Alive*

• Standard First Aid*

• WHMIS*

• TDG*

• Safety Management and Regulatory Awareness For Wellsite Supervision*

• Detection and Control of Flammable Substances*
**2.14.5.4 Rig Manager**

**IRP** The Rig Manager must have the following minimum experience levels:

- 5 years experience as a Rig Manager or driller.
- Must have been involved (as rig manager) in 5 Workover or Completion operations while these wells were in the sour zone.
- Work must have been conducted on wells of similar depth and complexity.

The training/certification requirements are:

- Well Service BOP
- H₂S Alive
- First Aid
- WHMIS
- TDG
- Confined Space Entry (pre-entry portion)
- Fall protection

**2.14.5.5 Rig Crew**

**IRP** Each member must be competent to fully handle their individual responsibilities and to fully understand their responsibilities for the Critical Well Control Operation.
IRP The minimum experience level of each member of the crew should be a minimum of 6 months working on sour workover and completion operations of similar depth and complexity in the position they are assigned to.

The Driller must have minimum of 2 years experience as a Driller on sour operations of similar depth and complexity.

IRP Rig Crew Personnel must have the following valid training certificates:

- H₂S Alive
- First Aid
- WHMIS
- TDG
- Confined Space Entry (pre-entry portion)
- Fall protection

In addition to the above training, the Driller must possess a valid Well Service BOP Certificate.

2.14.5.6 H₂S Safety Service Supervision

IRP The H₂S Safety personnel must be competent in the following:

- Breathing Air Equipment
- Atmospheric Monitoring Equipment (H₂S and LEL monitors both portable and multi station).
- Work Site Safety Management
- Co-ordination and Safety Management of Company Emergency Response Plans as they pertain to the Operations being conducted on the well.

The training/certification requirements are:

- H₂S Alive
- First Aid
- CPR
- TDG
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- WHMIS
- Confined Space Entry and Rescue
- High Angle Rescue

**IRP**

The Primary Safety supervisor shall have a minimum of 18 months of experience in H₂S Safety with a minimum of 6 months experience in conducting Wellsite Safety Supervision on Critical Sour Wells.

If the Operational Complexity dictates the need for additional H₂S Safety Personnel, additional safety supervisors may have a lesser degree of experience; however, the training should be the same as detailed above. The minimum of experience should be 6 months of Safety Supervision on Sour Operations.

**2.14.5.7 Employer Personnel (Service Company Personnel Other Than Rig Operations Personnel)**

**IRP**

The minimum experience level of each member of the crew must have a minimum of 6 months working experience on sour workover and completion operations (of similar complexity and depth) in the position they are assigned to.

If the workers are not experienced in the operations on sour wells, the employer supervisor must treat the worker as not competent and the worker must be kept under close supervision at all times.

Specific requirements for services are outlined in the various sections of IRP 2. The personnel that are the employees of the service companies providing these services are trained to conduct the operations on normal wells with normal emphasis on safety and well control.

When operating on a Critical Sour Well, the supervisors and equipment operators are expected to have a minimum level of experience that is appropriately equal to those required of the service rig employees.

It is expected that the supervisors of the service company crews and their employees be trained in the requirements as outlined in IRP 2 that specifically deal with their work. For instance, a crew that works for a Wireline Service Company would be required to be trained in the requirements as set out in the sections of Braided Line and Slick Line services. Personnel that are on location to provide Snubbing Services would be required to have knowledge and training on the requirements...
of snubbing operations and BOP control equipment as outlined in the sections of this document.

It would be up to the Operator to determine that the service provider being considered for the service has adequately trained their personnel in those sections of IRPs and legislation covering their work prior to placing them on the vendor list of the program. A review of the crew’s qualifications would also be a point for the wellsite supervisor to query when ordering out the service and when bringing the service crew on the location.

2.14.5.8 Other Personnel

Any personnel involved in the operation either as a worker or as an observer or technical specialist must have the following valid training certification and knowledge:

- H₂S Alive
- First Aid
- WHMIS

Personnel not having the above training and knowledge must be restricted from active involvement in the operation whereby they would be subjected to the various hazards found on the location (H₂S gas, chemicals, and mechanical hazards associated with pressure and the more complex equipment configuration).

2.14.6 Certification and Training Course References

The Certification and Training Courses in this IRP refer to courses offered - or equivalent courses sanctioned by - Enform. Full details are available at www.enform.ca
List of References
