DACC

DRILLING AND COMPLETION COMMITTEE

IRP 21:
Coiled Tubing Operations

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

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21.0 Preface

21.0.1 Purpose

The purpose of this document is to ensure that guidelines for coiled tubing operations are in place and readily available for all personnel involved in the development, planning and completion of coiled tubing well servicing operations.

IRP 21 is intended to supplement existing standards and regulations. It is also intended to establish guidelines in areas where none existed previously.

Current Occupational Health and Safety and jurisdictional regulations must be consulted. The inclusion of extensive quotes from, or references to, these regulations has been minimized to avoid references to out-of-date regulations.

21.0.2 Audience

The intended audience for this document includes oil and gas company engineers, field consultants, coiled tubing personnel, service rig personnel, well testing and fluid hauling personnel, other specialized well services personnel, coiled tubing manufacturers and jurisdictional regulators.

21.0.3 Scope and Limitations

This IRP applies to all coiled tubing well servicing operations performed in a wellbore.

These recommendations are considered to be the minimum recommended procedures and best practices necessary to carry out operations in a manner that protects people (the public and workers) and the environment.

IRP 21 is intended to provide guidelines and best practices for coiled tubing operations in all jurisdictions in Canada. Regulations in the applicable regulatory jurisdiction must be consulted and followed.

IRP21 refers to other relevant standards where appropriate and provides information on how to access them (see Appendix C: References).

21.0.4 Revision Process

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

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

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

21.0.5 Sanction

The following organizations have sanctioned this document:

Canadian Association of Energy Contractors (CAOEC)

Canadian Association of Petroleum Producers (CAPP)

Petroleum Services Association of Canada (PSAC)

Explorers & Producers Association of Canada (EPAC)

21.0.6 Range of Obligations

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

Table 1. Range of Obligation

Term	Usage
Must	A specific or general regulatory and/or legal requirement that must be followed. These IRP statements are bolded for emphasis.
Shall	An accepted industry practice or provision that the reader is obliged to satisfy to comply with this IRP. These statements are bolded for emphasis.
Should	A recommendation or action that is advised
May	An option or action that is permissible within the limits of the IRP
Can	Possibility or capability

21.0.7 Background

21.0.7.1 **Equipment Used in Coiled Tubing Operations**

Coiled tubing equipment includes the BOP, coiled tubing stripper, reel, injector head, control cabin and power pack. Auxiliary equipment generally includes fluid pumps and nitrogen pumps. Equipment functionality is outlined in Table 2.

Table 2. Coiled Tubing Equipment Functionality

Equipment	Purpose
BOP	Provide emergency well control
Coiled Tubing Stripper	Provide primary well control
Reel	Storage and transportation of the coiled tubing
Injector Head	Provides the surface drive force to run and retrieve the coiled tubing
Control Cabin	Allows the equipment operator to monitor and control the coiled tubing
Power Pack	Generates the hydraulic and pneumatic power required to operate the coiled tubing unit

21.0.7.2 **Drilling Operations**

Editions 1 and 2 of IRP 21 included recommended practices for coiled tubing drilling operations (both underbalanced and overbalanced). During the review for Edition 3 DACC decided that the drilling sections of the document would be removed. Forward any questions or concerns about the drilling content to DACC via the feedback mechanism noted on the IRP 21 page on the Energy Safety Canada website.

21.1 Introduction

For purposes of this IRP coiled tubing is defined as continuously manufactured steel tubular product spooled onto a take-up reel.

Coiled tubing operations are upstream petroleum industry operations using specialized equipment and qualified personnel to carry out workovers and drilling on oil and gas wells. Coiled tubing applications fit into two general categories: fluid conveyance applications (pumping) and mechanical applications.

Fluid conveyance applications include, but are not limited to, the following activities:

- Removing sand or fill from a wellbore
- Fracturing/acidizing a formation
- Unloading a well with nitrogen
- Conducting gravel packing
- Cutting tubulars with fluid
- Pumping slurry plugs
- Isolating zones (to control flow profiles)
- Removing scale (hydraulic)
- Removing wax, hydrocarbon or hydrate plugs

Mechanical applications include, but are not limited to, the following activities:

- Setting a plug or packer
- Fishing
- Perforating
- Logging
- Removing scale (mechanical)
- Cutting tubulars (mechanical)
- Shifting Sleeves
- Running a completion
- Performing straddles for zonal isolation

The IRP includes information about coiled tubing operations including recommendations for the following:

- Operations planning
- Well Control Equipment
- Accumulator Equipment
- Coiled tubing specifications
- Fluids and circulating systems
- QA for Well pressure control equipment
- Elastomeric seals
- Well servicing operations

21.2 Planning

IRP Planning for coiled tubing operations shall include determining the appropriate equipment specifications and configurations required for the job. This includes any necessary engineering calculations.

21.2.1 Well Information and History

IRP A review of current and historical well condition should be performed prior to conducting operations.

21.2.2 Job Objectives

IRP Job objectives should be documented and include a brief summary of the work to be completed.

21.2.3 Fracturing with Coiled Tubing

IRP The following should be considered when planning Fracturing with Coiled Tubing (FWCT) operations:

- Mode of communication during concurrent operations with fracturing operations, flow back control and down-hole tool operations.
- Ability to monitor and/or predict reductions in coil tubing wall thickness and temporary pipe work exposed to the abrasive fracturing fluid systems.
- Ability to manage pressure differential across coiled tubing during annular fracturing treatments.
- Adequate coiled tubing protection in the form of a coil deflector sleeve or similar diversion device.
- Include sufficient barriers for the pressure category if the check valves are removed from the BHA (see 21.3.2 Well Control Components as Barriers and 21.3.3 Pressure Categories).

IRP The induced pressures encountered during fracturing operations shall be included in the maximum pressure calculations (see MAIP calculation in 21.3.1 Determining Pressure Requirements).

21.2.4 Hazards and Safety

IRP Coiled tubing operations planning shall include a review of each coiled tubing operation to evaluate the hazards the operation would present.

IRP Procedures shall be in place to address any potentially hazardous situation identified.

IRP Safety meetings with all shift personnel on site shall be held

- before starting operations,
- before continuing with an operation that has substantially changed due to changing well or lease conditions,
- before any hazardous operation and
- at shift change.

IRP There shall be procedures in place for, at minimum, the following situations before commencing operations:

- Explosive potential of trapped or pressurized air
- Coiled tubing overpressure/overpull
- Coiled tubing integrity loss
- High pressure cycling/snubbing
- Coiled tubing run-away
- Coiled tubing stuck in hole
- Chemical/explosive cutting of stuck coiled tubing
- Reel/spooler drive motor failure
- Pulling coiled tubing through stripper
- Fishing live perforating guns
- Stripper element, pressure control or injector work
- Crane safety
- Lockouts
- Working at heights
- H_2S gas release
- Sour gas/corrosive environments

See Appendix C: References for general safety references.

21.2.5 Emergency Response Plan

IRP Regulatory requirements must be consulted for Emergency Response Plan requirements and content.

IRP Site-specific Emergency Response Plans shall be used in conjunction with the prime contractor's generic or corporate Emergency Response Plan.

IRP The ERP shall consider the coiled tubing specific hazard zone.

Determine muster point at pre-job safety meeting considering the site equipment layout and designate personnel for emergency situations (e.g., sour release, coiled tubing failure, equipment failure, etc.).

21.3 Well Control Equipment

The well control equipment sections were developed with the consideration that the hydrostatic head of the fluid column may no longer be the primary method of well control.

21.3.1 Determining Pressure Requirements

Determining the appropriate pressure category and equipment requires definition of the Maximum Anticipated Surface Pressure (MASP), Maximum Allowable Operating Pressure (MAOP) and Maximum Allowable Induced Pressure (MAIP).

There are three steps to selecting the appropriate well control equipment:

1. Determine MASP (Equation 1) to select the pressure category. This determines the minimum number of barriers and required functions (see 21.3.2 Well Control Components as Barriers for the definition of coiled tubing barriers).
2. Determine the MAOP for the wellhead and well control equipment being used (Equation 2).
3. Determine the MAIP for the planned operation (Equation 3) to ensure that the working pressure rating of the casing, wellhead and well control equipment will not be exceeded.

For example, a low pressure well may require the functions and barriers of pressure category 1 but due to the induced pressure of an annular fracturing operation, a 68.9 MPa working pressure may be necessary.

> **Note:** It is important not to confuse these two subjects. Pressure category and working pressure are separate considerations.

MASP is the Maximum Anticipated Surface Pressure. It is used to calculate the maximum wellhead pressure that the formation can exert on surface when the wellbore contains only formation fluid.

If formation fluid is unknown base the prediction on formation pressure minus a wellbore filled with dry gas from the surface to the true vertical depth of the completion interval.

Equation 1. MASP

$$MASP = Reservoir\ Pressure\ - Hydrostatic\ Pressure\ of\ a\ Column\ of\ Reservoir\ Fluid$$

IRP Calculation of MASP shall use the reservoir fluid and not the workover fluid.

MAOP is the Maximum Allowable Operating Pressure. It is the highest pressure that wellhead, casing and well control equipment can be subjected to during the execution of the prescribed service.

This IRP defines the Pressure Test Value as the lowest working pressure rating of any exposed wellhead component (i.e., the pressure rating of the weakest component).

> **Note:** A contingency kill program may use up to 100% of the pressure test value.

Equation 2. MAOP

$$MAOP = \ Pressure\,Test\,Value\ \div 1.1$$

MAIP is the Maximum Allowable Induced Pressure for well servicing work.

Some well servicing procedures require induced pressures, which effect the wellhead pressure, to accomplish the scope of work that is being planned. The induced pressure may be caused by circulating through the coil tubing or pumping from surface into the annulus. Examples of these job types include, but are not limited to, acidizing, annular fracturing, fracturing through coil (reverse circulation), as well as single cup / packer using back side as dead leg pressure monitoring, cement squeezing and well kill operations.

The safe and successful execution of an induced pressure well servicing operation requires planning for the MAIP limitation.

Based on the type of well servicing procedure being planned, some calculations will enable the operator and the service company to determine whether the scope of work can be accomplished with existing wellhead equipment or if specialized equipment (e.g., fracture heads, fracture strings, blast joints, etc.) need to be considered. Alternatively, a review of the procedure may be required to accomplish the well servicing procedure with the existing wellhead equipment.

Equation 3. MAIP

$$MAIP = MAOP - (Reservoir\ Pressure\ - Hydrostatic\ Pressure\ of\ Workover\ Fluid)$$

IRP Operating pressure shall not exceed the pressure rating of any well component that has the potential to be exposed during the well intervention.

IRP Induced pressure shall not exceed the rated working pressure of the well control equipment, wellhead or casing.

IRP Minimum pressure rating of equipment shall be the greater of 1.1 times MAOP or MASP (1.3 times for critical sour).

21.3.2 Well Control Components as Barriers

Coiled tubing well control components provide the necessary barriers to prevent an uncontrolled flow of wellbore effluents to the surface. These barriers can include a tested mechanical device or combination of tested mechanical devices. This document refers to these simply as barriers for coiled tubing operations.

Complete barriers are mechanical devices that, when closed, completely close off the wellbore. Annular barriers are static sealing elements only (i.e., no tubing is permitted to move when it is functioned in the closed position). The pressure category dictates the complete and annular barrier requirements for the operation (see Table 3 in 21.3.3 Pressure Categories).

Examples of complete barriers are as follows:

- A single blind ram and a single shear ram or a combination Shear/Blind ram that, when closed, completely shuts off the wellbore.
- The combination of an annular sealing component (such as a pipe ram or annular BOP) and a flow check assembly installed within the coiled tubing BHA that together completely closes off the wellbore.

An example of an annular barriers is a pipe ram or annular BOP which, when closed, shuts in the annular space between the coiled tubing and the wellbore.

Annular barriers used in conjunction with a flow check assembly to create a complete barrier can also be counted as standalone annular barriers as per the pressure category requirements (see Table 3 in 21.3.3 Pressure Categories).

Working sealing devices are not considered to be annular barriers. A coiled tubing stripper is a working sealing device and, by itself, is not considered to be an annular barrier and it can not replace any other pipe-sealing element required in the stack (see Table 4 in 21.3.4 BOP Stack Functions by Pressure Category). This includes a dual or tandem stripper. Annular packers are also working sealing devices and are not considered to be barriers.

IRP A flow check assembly installed on the end of the coiled tubing string used in combination with an annulus-sealing component (pipe ram or annular BOP) in the well control stack shall be considered only one complete barrier, regardless of the number of annulus-sealing devices installed in the well control stack.

21.3.3 Pressure Categories

The pressure categories in Table 3 were developed for IRP 21 to allow consistent terminology that does not reference the various provincial regulators. Different regulations, industry recommended practices and best practices may apply for different well servicing categories. For any conflict or uncertainty regarding which category to follow refer to the higher category (i.e., the one with the more stringent requirements).

Complete and annular barriers referenced in this table are defined in 21.3.2 Well Control Components as Barriers.

IRP The barrier requirements for well servicing shall be as outlined in Table 3 and 21.3.2 Well Control Components as Barriers.

Table 3. Well Servicing Pressure Categories

Pressure Category	MASP	Complete Barriers Required	Annular Barriers Required
Category 1	0 MPa	As per local jurisdictional regulations	As per local jurisdictional regulations
Category 2	0.1 – 5.3 MPa	1	1
Category 3	5.4 – 31.0 MPa	2	1
Category 4	31.1 – 52.0 MPa	2	2
Category 5	52.1 – 93.0 MPa	3	2
Critical Sour	See IRP 02: Completing and Servicing Sour Wells	3	2

Note: A pressure category 1 well is one that is unable to flow under any circumstances. Local jurisdictional regulations for non-flowing wells vary and may require some form of complete and/or annular barrier (based on jurisdictional classification).

Note: Annular barriers used in conjunction with flow check assemblies to create a complete barrier can also be counted as standalone annular barriers.

Note: The main function for a second annular barrier (category 4 and higher) is to provide redundancy for pipe ram or coiled tubing stripper in a high pressure or sour application.

Note: A low pressure well may require the functions and barriers of pressure category 1 but due to the induced pressure of an annular operation, a 68.9 MPa working pressure may be necessary.

IRP 21 defines a sour well as a well with any level of H_2S and a critical sour well as a sour well that meets specific release rate and proximity criteria as defined as the local jurisdictional regulator.

Note: In B.C. regulations these wells are called 'Special Sour'.

Refer to IRP 02: Completing and Servicing Sour Wells for more information about critical/special sour wells.

IRP Category 1 and 2 wells that are sour shall meet the barrier and function requirements of category 3.

IRP Category 3 wells that are sour shall meet the barrier and function requirements of category 4.

IRP Pressure category 5 and critical sour well operations shall have detailed risk assessment and contingency plans in place prior to opening the wellhead.

21.3.4 BOP Stack Functions by Pressure Category

Table 4 lists the required functions of the BOP stack for each pressure category. This table assumes flowback is taken through the tree below any coiled tubing well control equipment. More detailed descriptions of the functions and sample illustrations, including variations for sour wells, can be found in section 21.3.5 BOP Stack Configurations.

IRP Minimum functions for each pressure category shall be as per Table 4.

Table 4. Minimum Required Functions by Pressure Category

Well Control Component	Pressure Category					
	1	**2**	**3**	**4**	**5**	**Critical Sour**
Coiled Tubing Stripper	1	1	1	1	2	2
Shear Ram[1]			1	1	2	2
Blind Ram[1]			1	1	2	2
Kill Port			1	1	2	2
Slip Ram			1	1	1	1
Pipe Ram[2]		1	1	2	2	2
Flow Check Assembly		1	1	1	1	1

Note: Local jurisdictional regulations for non-flowing wells (pressure category 1) vary and may require some form of complete and/or annular barrier (based on jurisdictional classification).

Refer to IRP 04: Well Testing and Fluid Handling for ESD requirements when abrasive flowback is anticipated.

IRP For category 4, 5 or critical sour wells, if the top blind ram and shear ram are separate (not a combination) then a Shear/Blind ram shall be included below the standard well control stack in the event a collapsed pipe in the BOP prevents the top blind ram from closing (i.e., no pipe movement possible).

Where a Shear/Blind combination ram is used as the top ram, the secondary Shear/Blind ram is not required.

21.3.5 BOP Stack Configurations

Samples of recommended BOP configurations are shown below. Best efforts have been made to represent configurations that are typical in the industry but these configurations should not be considered exclusive of alternate configurations that provide equivalent or additional levels of well control (e.g., through combination ram functions or alternate pipe or wellbore sealing methods). Alternative configurations are acceptable as long as

[1] Shear and blind can be on the same ram functions.

[2] An annular BOP could be used in place of one Pipe Ram.

the proposed configuration and procedures manage the risk of spills, leaks and loss of well control to the same or higher level of certainty as the recommended equipment.

IRP 21 assumes that all operations will have a wellhead configuration that is compliant with IRP 05: Minimum Wellhead Requirements and all local jurisdictional regulations.

The configurations are based on pressure category as defined in Table 3 in 21.3.3 Pressure Categories. The recommended well control functions are identified in Table 4 in 21.3.4 BOP Stack Functions by Pressure Category. These functions may be achieved with single rams, combination BOPs or quad BOPs. IRP 21 does not recommend one configuration over another as long as all the required functionality is present.

Threaded connections are not recommended for wellheads in pressure category 3, 4, 5 or critical sour operations (Figures 3 through 6).

IRP The connections up to the uppermost BOP element must be flanged where local jurisdictional regulation requires the wellhead be flanged.

An integral hammer union of the same rating as the BOP body is permitted on the BOP side kill port provided there is a method of isolating this connection from the wellbore in the event of a leak. The most common configuration for this is a pipe ram below the kill port.

IRP Connections above the BOP shall be API 6A flanged connections or API 6A hand unions in pressure categories 3, 4, 5 and critical sour.

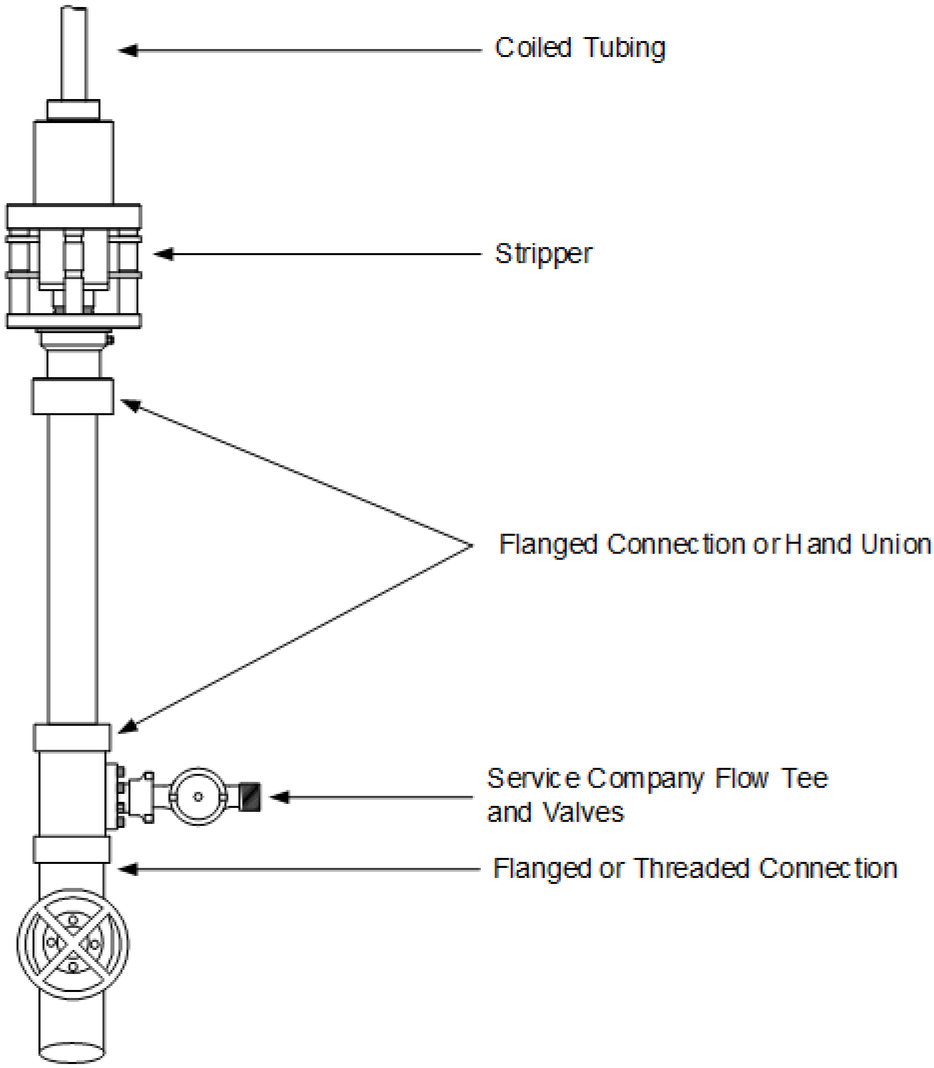
IRP All BOPs shall be hydraulically operated and connected to an accumulator system.

IRP For returns taken above the tree but below the primary BOP, an additional pipe ram below the flow cross or tee should be used for pressure category 2 or higher. Not required for category 1.

Wellhead valves and configurations in Figures 1 through 6 are shown as examples only and are not meant to be the only configuration or solution.

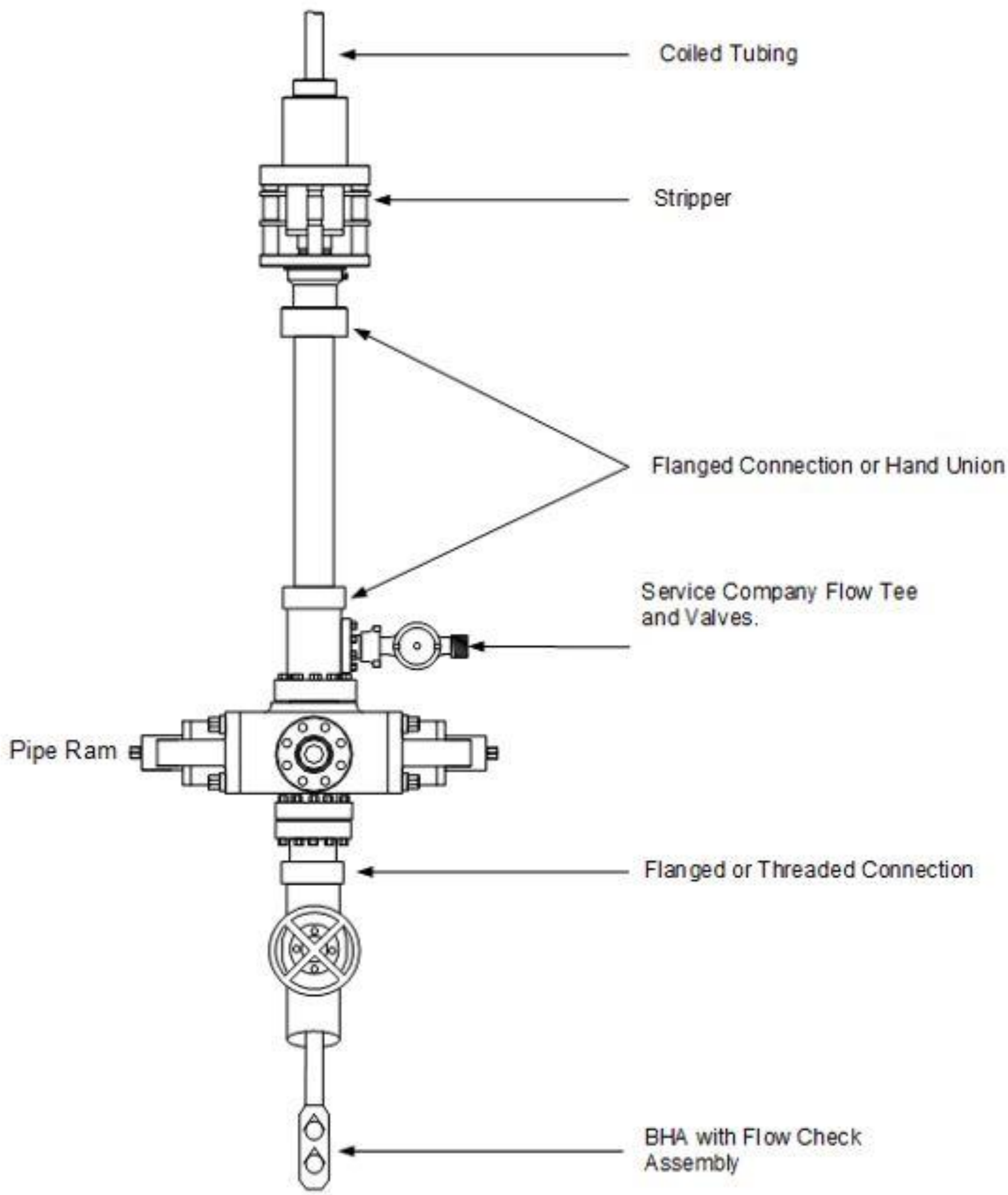
21.3.5.1 Category 1

Figure 1. Example Configuration for Pressure Category 1



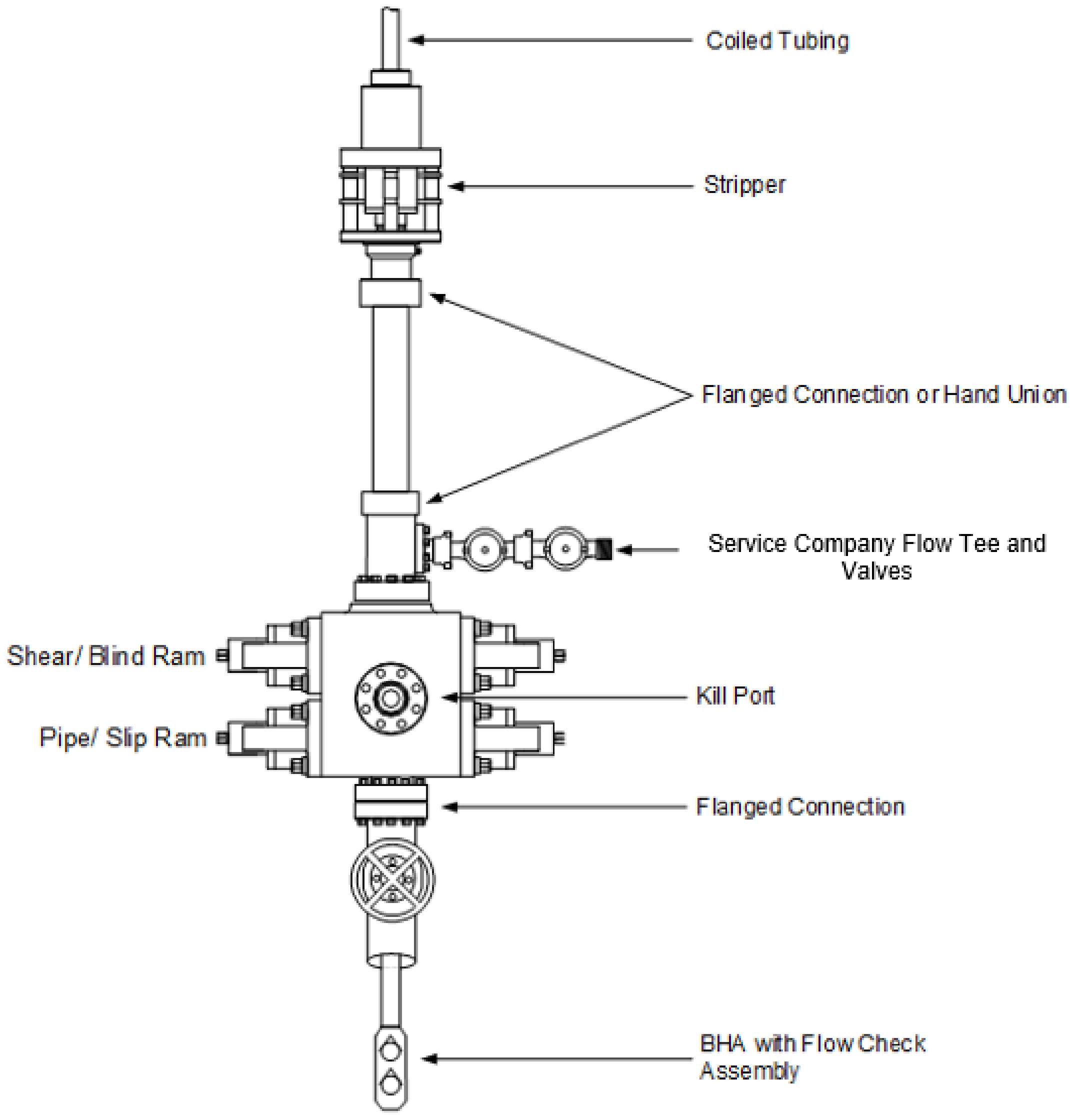
21.3.5.2 **Category 2**

Figure 2. Example Configuration for Pressure Category 2



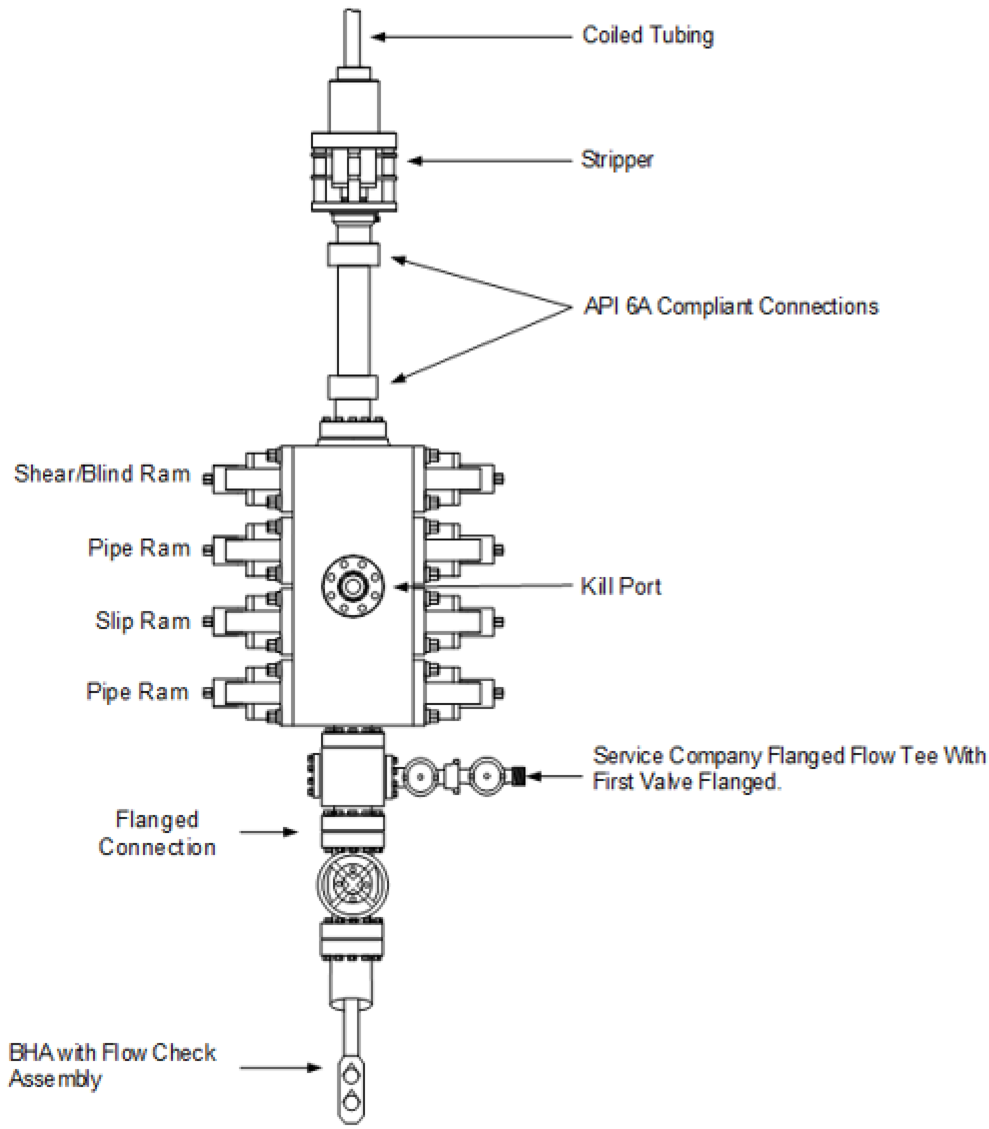
21.3.5.3 Category 3

Figure 3. Example Configuration for Pressure Category 3



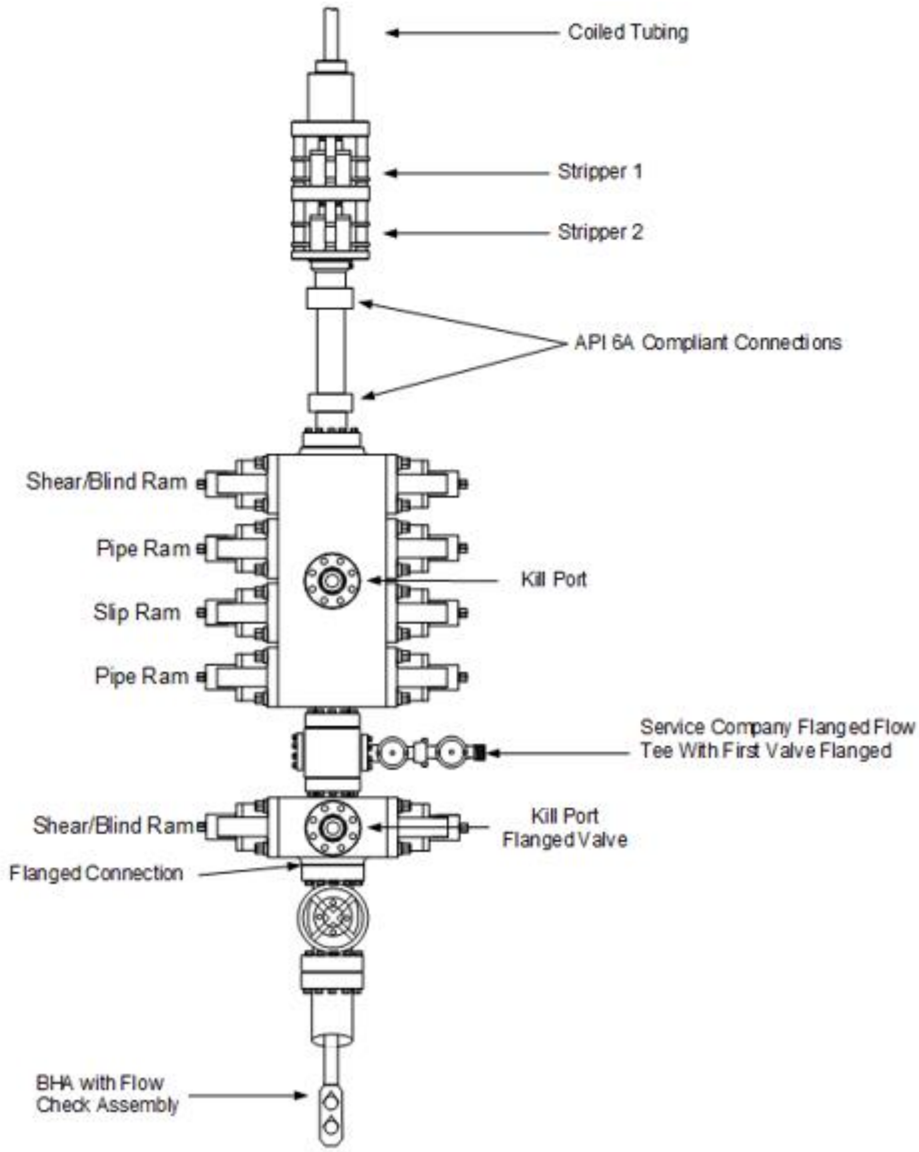
21.3.5.4 Category 4

Figure 4. Example Configuration for Pressure Category 4



21.3.5.5 Category 5 or Critical Sour

Figure 5. Example Configuration for Pressure Category 5 or Critical Sour



21.3.6 BOP Stack Considerations

IRP Sufficient support for the weight of the BOP equipment shall be in place to protect the wellhead from damage.

IRP The choice of well control component shall take into consideration the pressure testing requirements for the stack (i.e., from above or below or both) as some devices, and specifically some makes of rams, bags or valves, may be designed for pressure testing from below only.

IRP The choice of well control component shall take into consideration the maximum anticipated temperature during the operation, either from the wellbore or from the treatment fluids.

IRP Working pressure rating of all BOP components shall exceed MAOP by the pressure testing margin. Operating pressures during well servicing activities shall not utilize these contingency margins.

IRP BOPs should be placed directly above the wellhead assembly and below any lubricators.

This positioning avoids top-heavy BOP stacks and allows for manual control of the BOPs without the need for a man-basket or other lifting device.

21.3.7 Primary Flow Point

The primary flow point may be above, below or between the BOP elements. The abrasive and chemical nature of the produced/circulated fluids impacts the decision about placement.

IRP If the primary flow point is to be above the BOPs, a secondary kill port shall be available to allow for killing the well. The secondary kill port shall be placed below at least one pipe sealing element.

IRP If there is risk of washout of a flow tee or cross, an additional pipe sealing element should be below the potential washout point. Alternatively, fit-for-purpose flowback equipment should be used.

IRP If there is risk of washout of a flow tee or cross, an ESD valve should be used.

Refer to IRP 04: Well Testing and Fluid Handling for more information about flowlines, ESDs and chokes.

Refer to 21.6 Elastomeric Seals for information about elastomer compatibility issues.

21.3.8 Flow Check Assembly

Flow check assemblies prohibit flow up the coiled tubing from the bottom of the string and protect against uncontrolled wellbore flow in the event of a tubing failure.

IRP In procedures where a flow check assembly cannot be used due to job design considerations, a complete barrier such as a single Shear/Blind ram or equivalent alternative, shall be installed in addition to the standard well control stack configuration (see Table 3 in 21.3.3 Pressure Categories).

IRP If wellbore fluids are to be reversed through the reel iron then fit-for-purpose inspected flowback equipment should be considered based on a risk assessment of the operation.

21.3.9 Reel Isolation Valve

An isolation valve is required inside the reel to prevent uncontrolled flow at surface in the event of either a rotating joint or high-pressure iron leak that is exposed to coiled tubing pressures. This valve needs to be capable of isolating the rotating joint and high-pressure iron from the wellbore during repair.

IRP An isolation valve shall be located at the reel and downstream from the rotating joint for well servicing and drilling operations where the well is, or is expected to be, live.

IRP The isolation valve should be remotely operated.

IRP In cases where a rotating joint is not run (e.g., hanging strings) the isolation valve shall be located at the core end of the coiled tubing string.

IRP An iron management system shall be in place for the reel iron, swivel and reel isolation valve (see Appendix B: Glossary for more information about iron management systems).

IRP The iron management system shall include, at minimum, pressure testing to a maximum anticipated working pressure and material thickness testing.

21.3.10 Pressure Deployment Considerations

IRP In any live well operation where the length of lubricator is insufficient to swallow the entire BHA above the blind rams or the wellhead valve, a deployment system shall be in place that provides the following:

- A method of holding the BHA in the BOP stack.
- A method of containing wellbore pressure during the deployment procedure.

IRP BOP elements in the stack designated for emergency well control shall not be used for deployment purposes.

The deployment system may be either

1. an enclosed hands-free deployment system or
2. an annular preventer or a set of pipe rams sized for the BHA that provide the required number of barriers for the pressure category. These components would be in addition to the well control components normally required.

21.3.11 Ram-Type BOP Elements

IRP Ram-type BOP elements shall be hydraulically operated, have a backup system (as per 21.2.15 Accumulator Configurations) and have the ability to be locked in service. A stand-alone Shear ram does not require a locking ability.

IRP Shear rams run in the BOP stack shall be capable of cutting the outer coiled tubing string, any inner strings (e.g., coiled tubing, wireline or capillary) or any combination of these strings.

IRP The hydraulic fluid requirements for the slip rams shall be included in the total fluid requirements for the BOP stack.

IRP The BOP body temperature must be kept above -10C. If low-temp elements are used BOP body temperature must be kept above -25C (see AER D037). Annular bags must be kept above -10C.

21.3.12 Pressure Testing

IRP Well control systems must be pressure tested to meet or exceed local jurisdictional regulations to assess well control system integrity prior to commencing operations.

IRP The coiled tubing pressure control system components (as per Table 4 in 21.2 3 BOP Stack Functions by Pressure Category) must be pressure tested individually prior to commencement of operations.

IRP If the duration of operations on a well exceeds 7 days, additional pressure tests must be conducted as soon as reasonably practical.

The following factors may influence the decision about frequency of pressure testing::

- Potential fluid effects on BOP elastomers (e.g., fluid type, temperature). See 231.6 Elastomeric Seals for more information.
- Potential for debris accumulation in BOP ram elements.
- Ability of the BOP rams to continue to function properly given well site activity and associated weather conditions.

IRP The prime contractor and service provider representatives must perform a daily walk around inspection of all pressure control components and ensure there is documentation of the inspection.

IRP A BOP coiled tubing operational drill must be performed and documented, at minimum, every 7 days for each shift.

BOP components included in the drill are to be selected based on the operation being performed and whether the coiled tubing is across the BOP stack. Coiled tubing crews need to be able to shut in the well and practice this shut in during the BOP drill.

IRP A horn should be used to alert the crew for the BOP drill.

IRP Pressure test values and maximum allowable operating pressure should be confirmed with the prime contractor's representative prior to commencing operations.

21.3.12.1 **Blowout preventer**

IRP A pump in point shall be located below the BOP to allow each element of the stack to be individually tested.

IRP A test flange or test stump should be used to avoid any un-identifiable pressure loss through the wellhead valves that would result in an unacceptable test.

IRP A recording device should be installed in such a way that it cannot be isolated from the pump in sub during the pressure testing procedure.

IRP Each element pressure test should be documented and recorded via chart recorder or electronic data acquisition system.

IRP A low pressure test for a minimum of 10 minutes at 1.4 MPa must be performed on each BOP element prior to performing the high test on the element.

IRP If the low pressure test exceeds 2.1 MPa the pressure shall be bled to zero and the test restarted.

IRP A 10 minute high pressure test for a minimum of 10 minutes must be performed to the lesser of 1.1 times (1.3 times for critical sour) the MASP or up to the lowest rated pressure component of the casing, wellhead or well control equipment.

IRP A successful pressure test must maintain a stabilized pressure of at least 90% of the test pressure over a 10 minute interval and should show zero visual leaks on any seals or connections.

21.3.12.2 BOP Stack, High Pressure Iron Components and BHA

IRP Once the stump tested well control equipment is installed on the wellhead, complete system pressure tests must be completed for the following pressure lines and stack components:

- High pressure iron, rotating joint, reel isolation valve and coiled tubing string.
- All connections within the wellhead stack including all flanges, lubricator connections and primary and secondary stripper elements.
- Flowback iron and valving to choke manifold.
- Kill lines.

IRP All tests must include a 10 minute low pressure test of 1.4 MPa and a 10 minute high pressure test to the lesser of 1.1 times (1.3 times for critical sour) the MASP, the MAOP or up to the lowest rated pressure component of the casing, wellhead or well control equipment.

IRP A successful pressure test should maintain a stabilized pressure of at least 90% of the test pressure over a 10 minute interval and should show zero visual leaks on any seals or connections.

IRP The BHA flow check assembly should be body tested to the maximum expected differential pressure prior to installation.

IRP The BHA flow check assembly shall have a negative pressure test after installation and prior to running in hole.

IRP The BHA flow check assembly pressure test should include a 10 minute negative test of at least 7 MPa.

21.3.13 Function Testing

IRP BOP function tests shall be completed between each operation or often as reasonably practicable or as per local jurisdictional regulations

IRP A function test of all affected rams should be performed any time a hydraulic system connection is changed, disconnected or reconnected.

IRP Closing time for rams must be under 30 seconds.

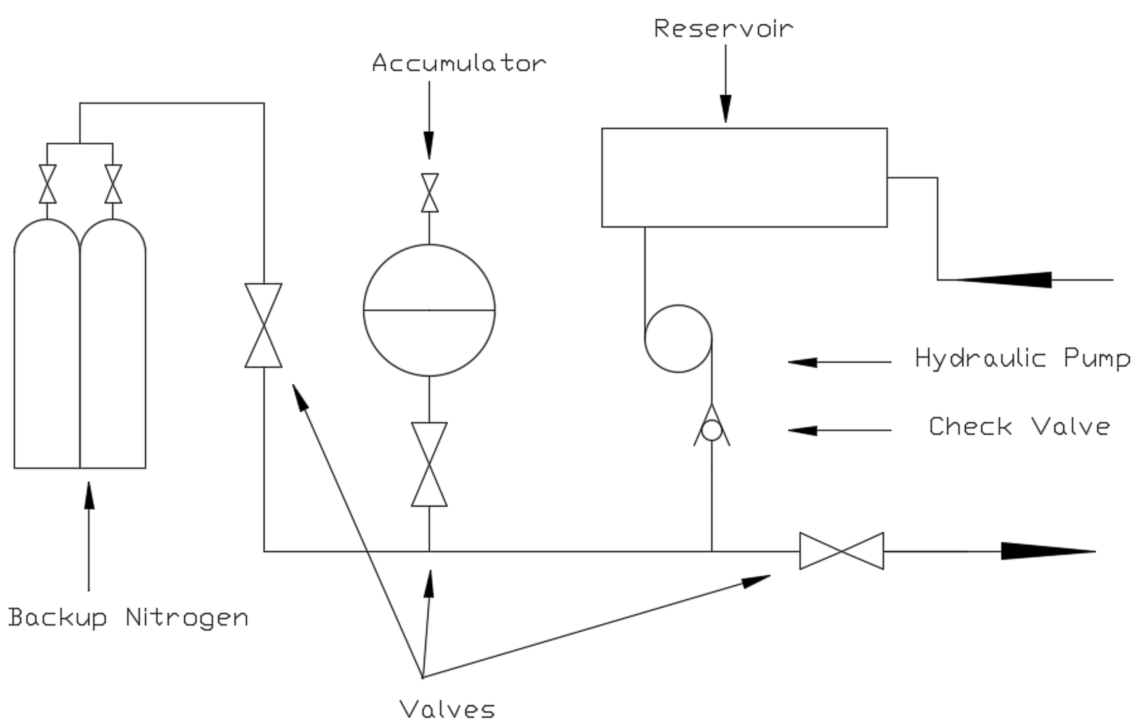
IRP Function tests must be visually confirmed.

21.4 Accumulator Equipment

Figure 6 shows a typical accumulator configuration for well servicing. Variances are permitted but all accumulator configuration IRPs have to be followed and the applicable functionality provided.

Requirements for the accumulator system are sourced primarily from AER Directives D036: Drilling Blowout Prevention Requirements and Procedures and D037: Service Rig Inspection Manual. Where there are differences between the directives, the IRP references information from D037.

Figure 6. Typical Accumulator System Configuration for Well Servicing Operations



21.4.1 Accumulator System Requirements

This section outlines the accumulator system requirements for well servicing operations with coiled tubing.

IRP **All BOPs must be hydraulically operated and connected to an accumulator system.**

IRP **The accumulator system must be capable of providing, without recharging, hydraulic fluid of sufficient volume and pressure to close all active BOP components at the same time (in their required function) and retain a minimum pressure of 8,400 kPa or the minimum pressure required to shear the tubulars (whichever is greater) on the accumulator system.**

Note: More than one accumulator system can be used to meet these accumulator system requirements.

IRP **All BOP equipment that is not in service must be locked out (e.g., unplugged, handles removed, lines disconnected, etc.).**

IRP **The accumulator system must be capable of functioning all active BOP components in the stack.**

Note: An active BOP component is any BOP component that is not locked out.

For annular preventers or pipe rams, this requires the preventer to be closed on the coiled tubing in use.

For blind rams, shear rams or BLIND/SHEAR rams, this requires the preventers to be closed without pipe in the hole.

IRP **All non-steel hydraulic BOP lines and line end fittings located within seven metres of the wellbore must be completely sheathed with adequate fire-resistant sheathing. Adequate fire-resistant sheathing for hydraulic BOP hoses is defined as a hose assembly that can withstand a minimum of five minutes of 700° C flame temperature at maximum working pressure without failure.**

IRP **The accumulator system shall be installed and operated according to manufacturer’s specifications.**

IRP **All accumulator specifications shall be available on site (i.e., manufacturer, number of bottles, capacity of bottles, design pressure, etc.).**

IRP The accumulator system shall be connected to the BOPs with hydraulic lines of working pressure equal to or greater than the working pressure of the accumulator.

IRP The accumulator system must be recharged by an automatic pressure-controlled pump capable of recovering a pressure drop (resulting from the function test of the BOP components) within five minutes.

IRP A check valve must be installed between the accumulator charge pump and the accumulator bottles.

This will allow for a change out of the charge pump in the event of a pump failure after the system has been energized.

IRP For all pressure categories that require an accumulator system, the accumulator system it must be

- capable of closing any ram-type BOP within 30 seconds,
- capable of closing the annular BOP within 60 seconds,
- equipped with readily accessible fittings and a gauge to determine the pre-charge pressure of the accumulator bottles,
- readily accessible and
- connected to a backup nitrogen system.

IRP For pressure category 1or 2 operations the accumulator must be located a minimum of seven metres from the wellbore. For other categories the distance is 15 metres or as per local jurisdictional regulations.

IRP For pressure category 3, 4, 5 and critical sour operations the accumulator must be as follows:

- Recharge pump must be independent from rig's hydraulic system.
- Shielded or housed to ensure that the system can be protected from the well in the event of an uncontrolled flow.
- Vented on the accumulator reservoir so that venting takes place outside of a confined space.

21.4.2 Backup Nitrogen Systems

This section outlines the backup nitrogen system requirements for well servicing operations with coiled tubing.

IRP **The backup N_2 system must be capable of providing the same functionality of the primary accumulator.**

IRP **The backup N_2 system must be connected such that it will function the BOPs without allowing the N_2 to discharge into the accumulator reservoir or the accumulator bottles.**

IRP **When the backup N_2 system is tied in downstream of an accumulator regulator valve or valves, isolation valves shall be in place to prevent venting of N_2 through the regulator into the accumulator reservoir tank.**

IRP **The backup N_2 system must be readily accessible and be equipped with a gauge, or have a gauge readily available for installation, to determine the backup N_2 pressure.**

IRP **For pressure category 1 and 2 operations the backup N_2 system must be located a minimum of seven metres from the wellbore.**

IRP **For pressure category 3, 4, 5 and critical sour the backup N_2 system must be located a minimum of 15 m (or as per jurisdictional requirements) from the wellbore and housed to ensure the system can be protected from the well in the event of an uncontrolled flow.**

21.4.3 BOP Operating Controls

IRP **The primary operating controls of the accumulator system shall be located at the normal operating location (i.e., control cab for deep units, back of truck for intermediate/shallow units) and remote locations for each BOP.**

IRP **The position of the operating handles (open/neutral/closed) of the BOP operating controls at one location (operator’s or remote) shall not prevent the operation of the BOP components from the other location.**

IRP **The crew shall be able to close the BOPs from the remote location.**

This setup allows the operating handles of the BOP controls to be repositioned without having to return to the coiled tubing unit in an emergency situation.

21.4.4 BOP Coiled Tubing Unit Operating Controls

IRP Each BOP component must have a separate operating control located near the operator's position.

IRP The BOP coiled tubing unit operating controls must be as follows:

- Capable of opening and closing each BOP component.
- Properly installed, readily accessible, correctly identified and show function operations (i.e., open and close).
- Equipped with a gauge indicating the accumulator system pressure.

21.4.5 BOP Remote Operating Controls

IRP Each BOP component must have a separate operating control located at a remote position with the same functionality as the primary control.

IRP The BOP remote operating controls must be as follows:

- Capable of closing each BOP component.
- Properly installed, readily accessible, correctly identified and show function operations (i.e., open and close).
- Be equipped with a gauge to determine accumulator system pressure.

IRP For critical sour wells the remote controls shall be capable of opening and closing each BOP component.

IRP For pressure category 1 and 2 operations the BOP remote operating controls must be located at a remote position a minimum of seven metres from the well.

IRP For pressure category 3, 4, 5 and critical sour operations the BOP remote operating controls must be located at a remote position a minimum of 25 m from the well. These controls must be readily accessible and shielded or housed to protect the controls in the event of an uncontrolled flow.

21.5 Coiled Tubing Specifications

The requirements in this section reflect the information and data currently available on coiled tubing pipe. It is recognized that ongoing research and testing may result in information that augments or supersedes what is contained in this document. Should such data show that the limitations contained herein are invalid, it is permissible to apply revised limitations provided that a comprehensive body of data exists to support the change. Comprehensive in this case would require testing of the material in sour conditions to identify fatigue limits and the effects of damage caused by the sour environment (e.g., hydrogen induced cracking, sulphide stress corrosion, stress corrosion cracking, etc.). Sufficient testing would need to be carried out to provide a statistically meaningful result.

21.5.1 Grades

Coiled tubing is categorized by its specified minimum yield strength (SMYS). Refer to manufacturer specifications of tubing grades for yield strength and hardness information.

Hardness maximums may be determined by conversion from micro-hardness scales (such as Vickers and Knoop).

21.5.2 Evaluating Suitability

IRP A computer-based coiled tubing simulator or other documented calculation methods should be used to evaluate the suitability of coiled tubing strings for Well Servicing Category 1 and 2 operations.

IRP A computer-based coiled tubing simulator or other documented calculation methods shall be used to evaluate the suitability of coiled tubing strings for the Well Servicing Category 3, 4, 5 and Critical Sour operations.

IRP The evaluation process shall determine the outside diameter (OD), wall thickness (taper) and material yield strength of the coiled tubing strings required for the proposed operation.

IRP All critical sour wells shall have the evaluation performed and documented.

21.5.3 Assessing Mechanical Strength

IRP The mechanical strength of the coiled tubing string shall be sufficient to resist all applied forces and pressures with a specified margin of safety.

The margin of safety is typically 80% of yield. Asses the condition of used coiled tubing taking into consideration of the minimum wall thickness, corrosion, and/or mechanical damage.

IRP Evaluation and limitations of coiled tubing strings shall be monitored and string records updated throughout the string's functional life.

The von Mises equivalent (VME) stress, collapse resistance and burst resistance should be calculated using the actual tubing dimensions (if known) and the specified minimum yield strength. Otherwise, the calculation of these parameters should use the following values:

- Specified OD
- Specified minimum wall thickness
- Three percent ovality

Equation 4. Three Percent Ovality

$$0.03 = \frac{2 \times (OD_{max} - OD_{min})}{OD_{max} + OD_{min}}$$

21.5.3.1 **Maximum VME Stress**

IRP The maximum VME stress in the tubing during the operation should be less than 80% of the specified minimum material yield strength in the coiled tubing string.

21.5.3.2 **Collapse Resistance**

IRP The calculated collapse resistance of the tubing at the maximum expected tension should be greater than 125% of the maximum expected collapse pressure.

IRP Collapse resistance should assume zero coiled tubing internal pressure and the greater of the measured maximum ovality or three percent ovality.

21.5.3.3 **Overpull at the Maximum Depth Planned**

IRP Overpull at the maximum depth planned for the coiled tubing operation should be the greater of

- 125% of the tensile force required at the end of the coiled tubing string for the service or
- 125% of the tension required to operate a disconnect (if equipped).

21.5.3.4 **Burst Resistance**

IRP The calculated burst resistance of the tubing should be greater than 125% of the maximum expected pump pressure.

IRP Burst resistance shall assume zero pressure outside the coiled tubing.

21.5.3.5 **Maximum Accumulated Fatigue**

IRP At the conclusion of the planned coiled tubing operation, the maximum accumulated fatigue in any section of the coiled tubing string should not exceed the limits documented in 21.5.11 String-Life Management System.

21.5.3.6 **Coiled Tubing Geometry Limits**

IRP A coiled tubing string should no longer be considered suitable for well intervention operations if any of the following applies to any section of the string:

- The wall thickness is less than 90% of the specified wall thickness or de-rated the reduced wall thickness measured.
- The tubing has ballooned more than 5% (i.e., measured OD > 1.05 x specified OD).
- The annular clearance between the minimum ID of the stripper bushing and the OD of the coiled tubing is less than 0.508 mm (0.020 inch). Bushing may be changed out to provide necessary clearance.
- The ovality is more than 5%.

21.5.4 String Properties

21.5.4.1 **Chemical Composition**

The steel composition of coiled tubing varies depending on manufacturer and steel grade. Consult with the manufacturer to ensure the chemical composition of the coiled tubing is suitable for the desired applications.

21.5.4.2 **Sour Environments**

NACE MR0175/ISO 15156 considers tubing as sour serviceable if the tubing hardness is equal to or below 22 HRC. However, all coiled tubing grades are susceptible to H_2S exposure/damage whether the coiled tubing meets the hardness requirements or not. This is due to stress and strains imposed on the coiled tubing steel while in operation.

IRP Mitigations should be implemented to minimize the risk of H_2S exposure to the coiled tubing.

See 21.5.12 Protecting Against H_2S Damage for more information.

21.5.4.3 **Mechanical Properties**

IRP The full-body material mechanical properties of coiled tubing strings for non-sour service should meet the coiled tubing manufacturer's product specifications.

IRP Coiled tubing used in sour service shall meet the following minimum requirements unless otherwise demonstrated as suitable for the specific application with appropriate mitigations in place:

Note: These requirements are based on the requirements in NACE MR0175/ISO 15156 and are interpreted for the specific characteristics of coiled tubing.

- Maximum hardness not greater than 22 HRC (or equivalent hardness scales).

Note: An exception can be made for quench and temper product that is equal to or less than 26 HRC.

- The maximum permissible hardness not to be exceeded at any point in the as-manufactured sour service coiled tubing string.
- Steel coils used to manufacture coiled tubing are to be produced by the hot-rolling process only.
- The longitudinal weld seam is to be annealed after welding.
- The tube body is to be stress-relieved after all tube manufacturing cold working.

IRP Coiled tubing used in sour service should meet the following minimum requirements:

- Microhardness is to be measured by the coiled tubing manufacturer from tube samples taken from the beginning and end of each string of tubing.
- Microhardness tests are to be performed in the as-milled (non-spooled) condition.
- A minimum of nine microhardness measurements is to be made on each sample as follows:

- Three measurements on the longitudinal weld seam.
- Three measurements in the longitudinal weld seam heat-affected zone (HAZ).
- Three measurements in base metal.

21.5.4.4 Tensile Properties

IRP Actual yield strength and tensile strength shall be measured by the coiled tubing manufacturer from tube samples taken from the beginning and end of the string of tubing (see ASTM-A450).

IRP Tensile tests should be performed in the as-milled (non-spooled) condition and on full-body tube samples.

If this is not possible on large-diameter and heavy-wall thickness samples, a reduced section (dogbone) sample is permissible.

IRP Tensile tests based on strip tensile (dogbone) specimens should be based on one specimen from each of the four quadrants of the coiled tubing specimen and averaged.

IRP Tests shall be performed as per ASTM A-370 and ASTM E8/E8M.

IRP Yield strength shall be determined by the 0.2% offset method.

IRP For tensile tests on used tubing the 1% pre-strain and offset method should be used.

For used coiled tubing strings the 0.2% offset method can give unrealistically low values due to the influence of residual stresses on the stress-strain curve.

IRP The 1% pre-strain and offset method should be used for tensile tests on used coiled tubing as per methodology described in SPE 38412: Determining the Mechanical Properties of Coiled Tubing.

21.5.4.5 Micro-Hardness Tests

IRP The 500 gram (or equivalent) micro-hardness tests of sections from full-tube specimens shall be performed as per ASTM E384 for at least three points in each of the following zones:

- Seam weld
- Seam-annealed area
- Base metal

IRP All hardness conversions from one scale to another shall be performed as per ASTM E140.

21.5.4.6 Flare and Flattening Tests

IRP Flare and flattening tests shall be performed on full-tube as per the more stringent of either of ASTM A450/450M (at minimum) or the coiled tubing manufacturer's documented specification requirements.

21.5.4.7 Hardness of Welds

IRP Hardness of welds in coiled tubing strings shall be as per Table 5.

Table 5. Hardness of Welds

Weld Type	Hardness
Bias Welds	Rockwell hardness (as per ASTM E18) in both the weld and HAZ not to exceed the maximum hardness specified for the coiled tubing string.
Tube-to-Tube Welds	Rockwell hardness (as per ASTM E18) for at least four equally spaced points around the weld circumference in both the weld and HAZ not to exceed that of the maximum specified hardness of the adjacent parent base metal.
Longitudinal Welds	Rockwell hardness (as per ASTM E18) in both the weld and HAZ not to exceed the maximum specified hardness for the adjacent parent base metal.

21.5.5 Welding Coiled Tubing Strings

21.5.5.1 Prohibitions

IRP Unless there is prior approval from the customer, a coiled tubing string containing a tube-to-tube weld shall not be used for any sour well.

IRP A coiled tubing string containing a tube-to-tube weld shall not be used for critical sour service.

21.5.5.2 Records

IRP Records of all tube-to-tube welds should be maintained for the life of the coiled tubing string.

IRP The welding service provider shall maintain a record (i.e., weld log) for each weld documenting the procedure used and the identification of the welder(s) who performed the weld.

21.5.5.3 Welded Tubing Connection at the Coiled Tubing Reel

IRP If the tubing connection to the coiled tubing reel plumbing is a welded fitting, the weld shall conform to a qualified weld procedure specification (WPS) performed by a welder in accordance with the welder qualifications and procedures.

IRP Non-destructive examination (NDE) inspections for welds shall be as follows:

- **Performed only after the weld cools to ambient temperature.**
- **Show no relevant indications regardless of size (as defined in ASNT-SNT-TC-1A).**
- **Unacceptable welds are to be cut out and re-welded.**

IRP All welds on tubing connections shall successfully pass one of the following:

- **A wet fluorescent magnetic particle inspection (MT) as per ASTM E709**
- **A liquid penetrant inspection (PT) as per ASTM E165/165M or**
- **A visual Inspection (VT) and confirmation of appropriate leg lengths per the WPS**

21.5.5.4 Welder Qualifications

For welder qualification information see 21.1.3.4 Welder Qualifications.

21.5.6 Non-Destructive Examinations

Additional information about Non-Destructive Examinations (NDE) of coiled tubing strings can be found in API Spec 5ST.

21.5.6.1 NDE of Coiled Tubing Strings

IRP An inspector certified to ASNT Level II for the applicable discipline shall approve NDE procedures.

IRP The approved NDE procedures should be available to the purchaser before the NDE is performed.

IRP If requested, the NDE service shall provide documentation for each NDE procedure that includes the following:

- **A description of the test parameters.**
- **The procedure number and revision level.**
- **A description of the acceptance criteria.**
- **The Level III inspector's approval signature.**

IRP All NDE should be approved by a technician/inspector certified, at a minimum, to ASNT Level I inspector status in the applicable inspection discipline and inspections should be in accordance with the latest edition of ASNT SNT-TC-1A or comparable customer-accepted standard.

IRP Documentation should be available to confirm calibration is current.

21.5.6.2 **Full-Length NDE of Coiled Tubing Strings**

IRP For new coiled tubing strings, the manufacturer shall perform automated NDE on the full length of the entire body of the coiled tubing string and the weld line for material discontinuities during manufacture.

IRP When NDE is requested on the full length of the entire body of a used coiled tubing string it should be completed after a satisfactory hydrostatic test (as per 21.3.8 Hydrostatic Proof-Testing of Coiled Tubing Strings) and before mobilizing the string for the next service operation.

IRP Any anomalies found during NDE should be flagged, measured and recorded. Anomalies should be reviewed with appropriate personnel to determine recommended course of action.

Actions may include the following:

- Repairing anomaly found on string
- Cutting out the anomaly from the string
- Derating the location on the string

IRP For intervention in all critical sour wells, an assessment shall be carried out to determine whether a full length NDE inspection of used coiled tubing strings is required. This should include, but not be limited to, operation complexity, well parameters, environmental concerns and previous history of the string.

21.5.6.3 NDE of Bias or Tube-to-Tube Welds in Coiled Tubing Strings

IRP NDE of bias or tube-to-tube welds in coiled tubing strings shall be as per Table 6 and as follows:

- All bias welds shall be 100% volumetrically inspected by radiographic testing (RT).
- Rejected welds shall be completely removed (cut out) and re-welded. Removing a flaw from a weld by grinding and filling in or overlaying the flaw is not acceptable.
- All NDE inspections of bias or tube-to-tube welds shall be performed with the weld at ambient (room) temperature.

Table 6. NDE of Tube-to-Tube Welds in Coiled Tubing Strings – Well Servicing

Weld Inspections	Pressure Category					
	1	2	3	4	5	Critical Sour
All welds **should** pass required inspections		Y				
All welds **shall** pass required inspections			Y	Y	Y	Y
All tube-to-tube welds 100% volumetrically inspected by RT UT with additional liquid penetrant testing (PT) for surface defects.			Y	Y	Y	Not Permitted

21.5.7 Automated Dimensional Inspections

The purpose of an Automated Dimensional Inspection (ADI) of a coiled tubing string is to determine if the tubing has any dimensional abnormality that would be detrimental to its performance during the intended service (i.e., any deviation from the intended cross-section geometry of the tubing). If an ADI of a coiled tubing string is conducted it should meet the requirements listed below.

IRP ADI of a coiled tubing string should be performed to a written procedure.

IRP The ADI equipment should meet the following criteria:

- Capable of creating a permanent electronic data file for each job. The data should be in a format that can be read with commonly available software.
- Include an electronic depth counter that
  - is capable of measuring the full length of the coiled tubing string,
  - has measurement resolution of ± 30 mm (0.1 ft.) or better and
  - has a tubing length accuracy of ± 0.5%.

- Calibrated to appropriate standards prior to and immediately following the inspection.
- Adjusted to produce optimum signal strength when the reference standard is scanned by the inspection unit in a manner simulating the actual inspection of the coiled tubing string.
- If capable of alerting the operator or marking the location on the coiled tubing for a dimension exceeding a specified limit, the limit(s) should be set according to measurement accuracy.
- The scanning rate of the inspection equipment and the running speed of the coiled tubing through the inspection equipment should be adjusted to provide multiple signals from a given inspection location on the tubing.

IRP The minimum acceptable outputs from automated measurements shall be as follows for each measurement location:

- Maximum OD (measured) ± 0.25 mm (0.01 in.)
- Minimum OD (measured) ± 0.25 mm (0.01 in.)
- Average OD (calculated)
- Ovality (calculated)

IRP The minimum acceptable output from automated wall thickness measurements is average wall thickness ± 0.13 mm (0.005 in) at each measurement location.

IRP Measurement locations should be as follows:

- All dimensional measurements are to be made at regularly spaced axial locations along the string.
- The maximum axial spacing between measurement locations is 1.52 m (5 ft.).

IRP OD and wall thickness measurements shall include at least four radials equally spaced around the tubing circumference.

IRP Dimensional inspection reports should be completed by the technician who performed the inspection. The report should include, at minimum, the following:

- The complete results of all ADI performed on a coiled tubing string.
- The axis of plots and headings for tabular data clearly identified and labelled with the corresponding units.
- Serial number or inventory control number of the coiled tubing string.
- Nominal OD, length, specified wall thickness and material of the coiled tubing string.
- Output from the inspection equipment for scans of the reference standards.

- Results from ADI of the coiled tubing string with the location of each indication exceeding the pre-set limits clearly identified.
- Disposition of each indication.
- Printed name and signature of the technician performing the inspection and the date of the inspection.

IRP The following dimensional inspection information should be available upon request:

- ADI methods used.
- Details about ADI equipment including serial numbers of all calibration standards and the last date of their verification.
- ADI procedures followed including reference number and revision level or date.
- Detailed description of the reference standards used and the detection threshold selected for ADI of the coiled tubing string.

21.5.8 Hydrostatic Proof-Testing of Coiled Tubing Strings

This section pertains to hydrostatic proof-testing of new coiled tubing strings, strings in storage or strings being tested (i.e., strings not at the wellsite).

IRP All coiled tubing strings shall be hydrostatically tested by the coiled tubing manufacturer before shipment and subsequently as required by the end user (service company).

IRP All tube-to-tube welds should have an initial hydrostatic test before operations begin.

21.5.8.1 Plumbing or Piping System

IRP The piping from the pressure source to the coiled tubing string shall be rated at a working pressure that exceeds the required hydrostatic test pressure.

21.5.8.2 Hydrostatic Test Pressure

IRP The required hydrostatic test pressure for new coiled tubing strings shall be, at minimum, as per the equation below and shall be recorded.

Equation 5. Hydrostatic Test Pressure

$$P_{HT} = \frac{1.60 \times \delta_{Y_{min}} \times t_{min}}{OD}$$

Where:

- OD = specified CT outer diameter
- Y_{min} = specified minimum yield strength of the material in the CT string
- t_{min} = specified thickness of the thinnest wall section in the CT string minus 0.127 mm (0.005 inches)

21.5.8.3 Test Medium/Fluids

IRP The pressurizing medium for all tests should be water or a water/antifreeze mixture having pH greater than seven and less than nine.

IRP Test fluid should be monitored and treated with a biocide chemical to prevent microbial induced corrosion on the tubing.

21.5.8.4 Pressure-Holding Periods

IRP Each pressure test should include a pressure-holding period of a minimum of 15 minutes with the minimum pressure drop of 3%.

IRP The timing of the pressure-holding period should not start until

- the test pressure has been reached and stabilized,
- the coiled tubing string and the pressure monitoring gauge/chart recorder have been isolated from the pressure source and
- the external surfaces have been thoroughly dried to make any leaks visible.

21.5.8.5 Acceptance Criteria

IRP The coiled tubing string shall show no visible leaks under the test pressure and any pressure drops evident on the pressure recording device during a hold period shall be less than three percent.

21.5.8.6 Pressure Measurement and Recording

IRP Pressure measurement and recording should be as follows:

- All pressure testing is to be performed with calibrated pressure gauges/transducers that have an accuracy of 0.5% of full scale and recorded on a calibrated chart.
- Pressure gauges and charts are to be chosen such that the test pressures fall between 25% and 75% of the full scale of the instrument.
- Charts are to be of sufficient scale to clearly show the tests.
- The recording device clock (time base) is to be set to clearly show the measured test line for each test and provide evidence that the chart line was not dropping or losing more pressure than allowed.
- Pressure test chart records are to be provided with the coiled tubing string's records.
- Each pressure test chart is to include the following documentation:
  - The coiled tubing string's description
  - The coiled tubing string's serial numbers
  - Test pressure
  - Test hold durations
  - Recording device and pressure sensor/transducer serial number
  - Printed name, signature and company affiliation of the designated test operator
  - Date, time and location of test
  - Printed name and signature of customer's representative (if applicable)

21.5.8.7 Removal of Liquids

IRP The testing contractor should use a documented procedure to displace liquid after the hydrostatic test is completed.

IRP After hydrostatic testing, the testing contractor shall ensure that the hydrostatic test fluid, gauge ball and all other debris have been removed completely from the ID of the tubing.

IRP The coiled tubing string shall be inhibited against internal corrosion and freeze-proofed prior to purging.

IRP Inert nitrogen gas and fluid removal pigs shall be used for purging.

Ensure the coiled tubing is completely evacuated and cap the ends of the coiled tubing once purged.

21.5.8.8 **Drifting/Gauging**

IRP All coiled tubing strings shall be drifted/gauged with a metal or nylon ball by the coiled tubing manufacturer before shipment and then again as required for the service or pending operation.

Refer to manufacturer specification for the acceptable diameter of the drift ball.

21.5.9 Coiled Tubing String Quality Management

21.5.9.1 **Manufacturing**

IRP The coiled tubing string manufacturer shall maintain and operate within the framework of a quality management system (QMS) that covers the manufacture of the coiled tubing strings.

21.5.9.1.1 Quality Plan

IRP The coiled tubing string manufacturer shall maintain and operate within the framework of a manufacturing quality plan (MQP) covering all operations, processes and activities performed at the coiled tubing manufacturer's manufacturing facility.

IRP The MQP should cover all the activities required by both the coiled tubing manufacturer's in-house quality inspectors and any inspection points required by the customer.

IRP The MQP should contain the following:

- A list of all major manufacturing, inspection and test activities.
- Procedure references (including revision levels) for each manufacturing, inspection and test activity listed.
- Acceptance criteria (or the procedure reference containing the acceptance criteria) for each inspection and test activity.
- Identification of the documents and records produced during manufacturing, inspection and testing that document the verification results of each activity.

IRP If the customer requires on-site quality control, the following provisions should be made:

- Allowance for the customer (or customer's third-party inspector) to monitor and witness the specific inspection and test activities.
- Initiation of an advance notification period during which the coiled tubing manufacturer provides notice to the customer to allow the customer representatives to participate as required in the listed inspection points.

21.5.9.1.2 Traceability

IRP The coiled tubing string manufacturer shall maintain traceability on all coiled tubing strings during manufacturing.

IRP This traceability shall be maintained to the original heats of steel strip used to produce the coiled tubing string and the associated certified material test reports (CMTR) providing acceptable test results for mechanical and chemical testing performed on the material.

21.5.9.1.3 Non-Conformance and Request for Exception

IRP The coiled tubing manufacturer should ensure that all non-conforming products are brought into compliance with applicable requirements.

IRP The coiled tubing manufacturer shall not allow non-conformances to be labelled "use-as-is" without first obtaining documented customer acceptance of the request for exemption from the specifications laid out in the IRP.

21.5.9.1.4 Quality Records

IRP The coiled tubing manufacturer shall maintain the following information for each coiled tubing string for a minimum of three years:

- Coiled tubing manufacturer's name.
- Date and location of manufacture.
- Manufacturer's serial number or other inventory control number for the string.
- Certificate of compliance /statement of conformity to product specifications and MQP.
- Total length of the coiled tubing string and length of each wall thickness section.
- Master coil and heat numbers for each strip in the string.
- Chemical analysis of each strip in the string.
- Mechanical properties of each master coil in the string including thickness, yield strength and ultimate tensile strength.
- Hardness.
- Full body mechanical properties of at least one sample of tube from each end of the milled string, including yield strength and ultimate tensile strength.
- Percent elongation in 50.8 mm (two inch) gauge length.
- Section micro-hardness for three points each in the seam.
- Weld, seam annealed area and base metal.
- Results of flare and flattening tests.

- Report on full body NDE approved by the NDE technician.
- Hydrostatic test data including the properties of the test fluid, maximum and minimum pressures and duration of each holding period.
- Chart record of the test.
- Drift results and diameter of the drift ball used.
- Procedure used to purge the coiled tubing string before storage/shipment.
- Procedure and chemicals used to protect the string OD and ID from storage corrosion.
- Weld log containing, at minimum, the location of each bias weld and location of each tube-to-tube (if applicable).
- WPS/PQR numbers.
- Welder identification.
- Report of NDE on each weld signed and dated by Level II NDE technician approving the examination.

21.5.9.2 Post Production Records

21.5.9.2.1 Traceability

IRP The end user of a coiled tubing string shall ensure traceability is maintained on the coiled tubing string.

IRP This traceability shall be maintained by unique serial number, inventory control number or other appropriate means.

IRP Traceability of coiled tubing strings shall be maintained to the following:

- **Manufacturer's CMTRs**
- **Quality records/data book**
- **End user's inspection and test reports, maintenance records and operating data**

21.5.9.2.2 End Use Documentation/Records

IRP The end user of a coiled tubing string should develop and maintain documentation for each coiled tubing string including the information noted for critical sour well servicing below.

IRP All records should be approved by the person completing the document or record.

IRP For critical sour well servicing, the following shall be developed and maintained:

- Inspection reports
  - Visual
  - NDE
  - Dimensional
- Hydrostatic test reports
- Each coiled tubing operation performed with a cross reference to appropriate coiled tubing string life management files
- Accumulated fatigue for each segment of the string on computerized managed strings
- Exposure to acid and composition of the acid
- Steps taken to protect coiled tubing against corrosion before a coiled tubing operation and to neutralize corrosion after the coiled tubing operation
- Exposure to H_2S and CO_2
- Exposure to abrasive fluids
- Fluids pumped for each coiled tubing operation
- Purging records
- Corrosion protection records
- Storage records

21.5.9.2.3 Velocity String Information for Installation and Removal

IRP The following should be recorded prior to installing a velocity string:

- Tube-to-tube welds in the string
- Downhole BHA, nipples or other completion equipment in the string
- Fatigue history of the string when installed
- Coil info (i.e., OD, length, grade (yield stress of material) and wall thickness)

21.5.10 Maintenance

IRP The end user should use a documented program for maintenance of coiled tubing strings as outlined in the list of tasks in this section.

21.5.10.1 **Cleaning the ID Surface**

IRP The individual coil end user should use due diligence to ensure the coiled tubing string being used is properly cleaned before each operation and tested to suit each pending operation.

21.5.10.1.1 Flushing

IRP Flushing procedures shall be as follows:

- Continue to pump clean fresh water or a water/antifreeze mixture after the trailing pig exits the coiled tubing string.
- The volume should be the greater of one full string volume or until the discharge is suitably clear, whichever is greater.
- Pump at a flow rate that will ensure turbulent flow.

21.5.10.1.2 Chemical Cleaning

IRP The procedures for chemical cleaning of coiled tubing strings should include the following:

- Use hydrochloric acid (HCl) or other chemical designed to chemically clean the ID of the string.
- Use a volume of chemical suitable for the inner surface area of the specific coiled tubing string.
- After pumping the cleaner through switch to clean fresh water or water/antifreeze mixture and continue pumping until the pH of the discharge is greater than six.

21.5.10.1.3 Neutralizing the Surface pH

IRP After chemically cleaning with acid the tubing surface shall be neutralized to eliminate any low pH spots that can lead to corrosion failures (pitting).

Consider the following:

- Use a neutralizer with a pH greater than nine and less than eleven.
- Use an adequate volume of neutralizer to achieve a pH of greater than six in the discharge.

- After pumping the neutralizer through the coiled tubing switch to clean fresh water or a water/antifreeze mixture and continue pumping until the discharge has pH greater than seven and less than nine.

21.5.10.1.4 Preparation for Storage

IRP Cleaned coiled tubing string that will not be used within 48 hours should have an internal and external corrosion inhibitor applied prior to storing.

IRP Biocide treatment should be conducted to the coiled tubing string after a procedure that had fresh water pumped through it prior to storage.

IRP The end user is responsible to ensure that a string of coiled tubing that is intended to be used after being stored for an undermined amount of time will perform their due diligence in ensuring the string is clean and usable.

21.5.10.2 Corrosion Protection

IRP If external corrosion protection is required, the coiled tubing manufacturer or end user shall uniformly apply a full-body coating of corrosion inhibitor to the exterior of the coiled tubing string.

IRP Coiled tubing should be purged and inhibited after a job. The volume of the inhibitor used should be adequate to coat the entire surface of the coiled tubing string based on the chemical manufacturer’s recommendations.

21.5.10.3 Managing Slack for Internal Electric Cable

IRP If a length of tubing is to be removed from a coiled tubing string containing electrical cable, the end user should ensure the total length of electric cable inside the coiled tubing string is at least 0.5 to 1.0% greater than the remaining length of the coiled tubing.

IRP If electrical cable is protruding from the end of the coiled tubing string before a coiled tubing operation, the end user should verify that the length of cable inside the coiled tubing string is at least one percent greater than length of the coiled tubing string before cutting back the excess. Otherwise, the end user should attempt to pump the excess cable into the coiled tubing string to achieve at least one percent excess length.

21.5.11 String-Life Management System

IRP The coiled tubing string-life management system for pressure category 1 and 2 wells should be adequate to prevent a string failure of the coiled tubing string due to accumulated low-cycle fatigue.

IRP The coiled tubing string-life management system for category 3, 4, 5 and critical sour wells shall be a computer-based system for tracking the cumulative low-cycle fatigue in each segment of a coiled tubing string.

IRP For category 3, 4, 5 and critical sour, the maximum segment length for tracking the cumulative low-cycle fatigue in each segment of a coiled tubing string shall be three metres (10 ft.).

The fatigue limits outlined below apply to computer-based systems only.

21.5.11.1.1 Retirement Criteria for Base Tubing

IRP A coiled tubing string shall be removed from service if the retirement limit, as determined by the end user, has been met.

IRP Retirement criteria should consider the following:

- Fatigue
- Service conditions in sweet and sour environments
- End user inspection requirements
- Storage procedures
- Ovality and/or ballooning
- Service life history
- Total running meters

21.5.11.1.2 Fatigue Limits for Welds

IRP Fatigue limits for welds shall be as per manufacturer specifications.

21.5.11.1.3 Fatigue Limits for Mechanical Splices

IRP Fatigue limits for mechanical splices shall be as per manufacturer specifications.

21.5.12 Protecting Against H_2S Damage

IRP The end user should use a documented method to minimize coiled tubing string damage during sour service operations from hydrogen embrittlement (HE), hydrogen induced cracking (HIC) and sulphide stress cracking (SSC).

IRP The end user should apply an H_2S inhibitor to the exterior of the coiled tubing string for Category 2 operations with sour conditions:

> **Note:** Addition of an H_2S scavenger to the circulated fluid for this category is **not** an acceptable substitute to application of an H_2S inhibitor as the section of coiled tubing adjacent to the perforations will be exposed to H_2S before it can be neutralized.

IRP The end user shall apply an H_2S inhibitor to the exterior of the coiled tubing string for category 3, 4 or 5 operations with sour conditions or any critical sour operations.

> **Note:** Addition of an H_2S scavenger to the wellbore fluid for these categories is **not** an acceptable substitute for application of an H_2S inhibitor.

21.5.12.1 **H_2S Inhibitor Properties**

IRP H_2S inhibitors shall be as follows:

- A fit-for-purpose anti-cracking agent. Products that only protect the coiled tubing against surface corrosion are not recommended.
- Compatible with the other fluids used during the operation.
- Compatible with all materials it could contact in the wellbore, pressure control equipment, downhole check valves and BHA components. The end user should be able to demonstrate H_2S inhibitor compatibility before starting the coiled tubing operation.

21.5.12.2 **H_2S Inhibitor Application**

IRP H_2S inhibitors should be applied by the end user with a documented method for application of the H_2S inhibitor to the exterior of the coiled tubing during the coiled tubing operation.

IRP The end user should be able to demonstrate that the application method effectively coats the entire exterior of the coiled tubing with H_2S inhibitor using the chemical supplier’s recommended practices.

21.5.12.3 H_2S Inhibitor Effectiveness

IRP The end user should be able to demonstrate the effectiveness of the H_2S inhibitor and its application method for protecting the coiled tubing string against damage from HE, HIC and SSC in the expected wellbore conditions during the coiled tubing operation.

21.6 Fluids and Circulating Systems

The following IRPs and guidelines address many aspects of fluids and circulating systems:

- IRP 02: Completing and Servicing Critical Sour Wells
- IRP 04: Well Testing and Fluid Handling
- IRP 08: Pumping of Flammable Fluids
- IRP 14: Non-Water Based Drilling Fluids
- Energy Safety Canada Fire and Explosion Hazard Management Guideline

Consult these references for recommended practices for fluids and circulating systems for coiled tubing operations.

21.6.1 Surface Equipment

21.6.1.1 **Pressure Rating**

Consider design working pressure limits of equipment during equipment selection to ensure it is capable of safe operations at the anticipated pressures.

IRP Circulating pumps, manifolds, discharge lines and return lines shall have a working pressure equal to or greater than 1.1 times the shut-in tubing pressure.

21.6.1.2 **Fluid Pump**

IRP The fluid pump shall have a discharge rate of sufficient capability (pump rate and worst-case pressure) to control the well.

IRP For winter operation the pump, manifold and surface lines shall be kept ice-free.

21.6.1.3 **Fluid Storage System**

IRP The fluid storage system shall provide for accurate fluid gauging.

IRP The fluid storage system shall prevent freezing of fluids

IRP If scavenger, inhibitor or other chemicals are required, an adequate and accurate means of mixing into the storage tank or flow stream should be used.

IRP Sour fluid storage tanks shall be in place for storage of all sour fluids.

Refer to IRP 04: Well Testing and Fluid Handling for more information.

21.6.1.4 **Closed System Circulation**

Sour effluent cannot be emitted to the atmosphere.

IRP Sour effluent shall 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-produced fluids.

IRP Fluid-gas separators (rig degassers) shall not be used on open rig tanks.

21.6.2 Completion and Workover Fluids

The primary functions of completion or workover fluids are to control formation pressure, transport movable solids and minimize formation damage. Selection of completion and workover fluids is determined based on site-specific operations and well conditions. Completion and workover fluids can range from complex high-density viscosified fluids to fluids such as fresh water, brines or hydrocarbon-based fluids.

IRP Precautions shall be taken to prevent explosion or ignition when using hydrocarbon or flammable fluids (see IRP 08: Pumping Flammable Fluids and Energy Safety Canada Fire and Explosion Hazard Management Guideline).

Injection of hydrocarbon or flammable fluid into an air-filled or partially air-filled well may provide favourable conditions for explosion or fire given a suitable ignition source.

IRP Fluids should be tested, monitored and treated with a biocide program to prevent internal or external microbial induced corrosion on the tubing and/or surface equipment.

IRP Coiled tubing/fluid pumpers should be purged with a biocide flush prior to purging with nitrogen.

For information on handling sour fluids and reducing the sour content refer to IRP 04: Well Testing and Fluid Handling and IRP 02: Completing and Servicing Sour Wells. See AER Directive 060: Upstream Petroleum Industry Flaring, Incinerating and Venting for information about flaring.

21.6.2.1 **Dissolved Sulphide**

A decrease in pH in a water-based fluid is an indicator that sulphides may be present in the fluid. Sulphides in the pumped fluid can damage the coiled tubing from the inside in the same way sulphides in the wellbore can damage the outside of the tubing.

IRP The presence of dissolved sulphides in the completion or workover fluid shall be determined.

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

IRP Sour fluids must be treated to 10 ppm H_2S before circulating to an open system or before pumping through coiled tubing and associated pumping equipment.

IRP Sour fluids should be treated to zero ppm H_2S before circulating to an open system or before pumping through coiled tubing and associated pumping equipment.

IRP Dissolved sulphides in the completion fluids shall be monitored by an individual competent in performing the chosen test method.

21.6.2.2 Completion Fluid Volume and Storage

IRP All fluid volumes on location shall be monitored and recorded at the following times:

- The start of each crew change
- Before and after filling the hole
- Before and after circulating
- Before and after tripping

IRP Before starting an operation there shall be 200% of active hole volume on surface. 100% of active hole volume shall be maintained on surface at all times.

Completion fluid storage capacity on location may include all appropriate storage vessels.

IRP For winter operations storage tanks shall be heated to prevent freezing.

Storage tanks equipped with properly maintained steam coils will prevent freezing and steam contamination of fluids.

21.6.2.3 Handling

IRP Written procedures and fluid specifications for safe handling and mixing of the completion/workover fluid shall be on location.

IRP Transportation of dangerous goods (TDG), Workplace Hazardous Materials Information System (WHMIS 2015) and applicable provincial occupational health and safety regulations must be followed.

IRP Safety data sheets (SDSs) shall be current and adhered to on site.

IRP Exposure monitoring and control must be as per the SDS and local jurisdictional regulations.

21.6.3 Use of Air

If there is a risk of air being in the system consult the Energy Safety Canada Fire and Explosion Hazard Management Guideline for guidance and a summary of critical risk factors.

Air may be used when drilling through non-hydrocarbon bearing zones. For further information on the use of air in Drilling Operations consult the Air Drilling section IRP 22: UBD/MPD/RMD Operations.

Consult local jurisdictional regulations for requirements.

21.7 QA for Well Pressure Control Equipment

Pressure Control Equipment (PCE) used in coiled tubing operations may or may not be governed by an API standard. The majority of PCE items that are API will be API 6A equipment such as flanged wellhead adapters, flanged flow tee's/crosses and flanged lubricators. PCE items that do not have an API standard are BOP's, strippers, quick union lubricators, quick test subs, etc. (i.e., not referenced in the API 6A Purchasing Guideline).

Well operators and service providers are responsible for ensuring that all well pressure control equipment conforms to regulatory requirements and the recommended practices in this and other IRPs.

21.7.1 Manufacturing API Well Pressure Control Equipment

IRP **All pressure control equipment included in the scope of API 6A must be manufactured in compliance with API 6A and should bear the API monogram.**

IRP **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 assurance program.**

IRP **Technical quality requirements that are beyond the scope or exceed the technical/quality requirements of the applicable API specification shall be per manufacturer's written procedures.**

API Spec Q1: Specification for Quality Program details all aspects of quality assurance program

21.7.2 Manufacturing Non-API Well Pressure Control Equipment

IRP **All pressure control equipment not included in the scope of API 6A shall be designed, manufactured and tested in accordance with API specification and API Spec Q1: Quality Program 1.**

IRP **A quality assurance program in compliance with API Spec Q1: Quality Program 1 shall be implemented.**

IRP The quality assurance program shall, at a minimum, include the following areas:

- Procurement control and traceability
- Incoming inspection
- Calibration of measurement and testing equipment
- Design and Development
- Quality records
- Personnel qualifications
- Inspection plan
- Manufacturer's mark
- Size and rated working pressure
- Handling, storage and shipping procedures

21.7.3 Sour Service PCE

IRP All PCE equipment used in sour service must use materials that conform to NACE MR0175/ISO 15156.

21.7.4 Shop Servicing and Repairs

Servicing and repairs include cleaning, replacement of components or reworking of any API-specified dimension within the tolerances indicated in the applicable API specification. Remanufacture refers to rework of original equipment manufacturer (OEM) specified dimensions or welding.

IRP Shop servicing and repairs shall be done by either an API-licensed manufacturer or a company that meets the requirements in 21.7.2 Manufacturing of Non-API Well Pressure-Containing Equipment.

IRP Remanufacturing should only be performed by an OEM to ensure the proper operation of remanufactured equipment.

21.7.5 QA Documentation to End User

IRP The manufacturer shall include documentation to the end user of the equipment that includes the following:

- Certificate of compliance to the applicable standards of the equipment
- Any pressure testing charts or other validation test records performed at the factory
- For sour service equipment include the following:

- A data book with the material test reports (MTRs) of wellbore wetted materials to show traceability and compliance to NACE MR0175/ISO 15156
- Statement of conformance to NACE MR0175/ISO 15156

These records can be printed or electronic as long as they are accessible to field personnel.

21.8 Elastomeric Seals

The elastomer recommended practices in this section have been developed with consideration for well completion and servicing activities and environments recognizing the need for seal integrity under a variety of service conditions.

This section is intended to help coiled tubing service providers select elastomers for well pressure seals (e.g., stripper rubbers, lubricator O-rings, BOP ram seals, BHA O-rings). Seal design, plastic seals and metal-to-metal seals are outside the scope of this IRP so manufacturers need to be consulted.

Further details on the requirements for elastomeric seals can be found in IRP 06: Critical Sour Underbalanced Drilling.

21.8.1 Service Conditions

IRP Service providers should determine the compatibility between the seal material and the seal design for the intended service. The following factors should be considered:

- Seal movement. Differences between static (BOP) and dynamic (stripper) seals should be taken into consideration in the selection.
- Service period. The length of service should be considered when selecting seal materials as seal material will often perform satisfactorily for a short service period but would be unsuitable for extended service periods.
- Seal maintenance. 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 worst-case conditions that may occur during the planned service or drilling operation such as increasing H_2S or temperature.

Note: 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.

Service providers need to 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 or any chemical additives introduced to the well.

IRP Compatibility of any elastomeric seal with the intended service environment shall be determined when selecting materials and equipment for the completion or servicing of any well.

IRP Compatibility shall include 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: Many types of elastomeric seals are susceptible to attack and degradation due to corrosion and H_2S cracking inhibitors. Proper elastomer selection is critical.

IRP Manufacturer-supplied performance properties and recommendations should also be used to verify compatibility.

21.8.2 Testing and Evaluation

IRP The seal materials shall meet the intended service requirements.

IRP Specific testing of seals based on anticipated field conditions shall be performed if available information is not adequate for the service application.

IRP 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.

IRP A field-specific testing program should be considered to verify the manufacturer's recommendations or to determine an elastomer's suitability.

IRP Storage and handling should be included in the quality control program because many elastomers have a shelf life due to sensitivity to sunlight and humidity.

21.8.3 Quality Control

The first-line well pressure control seals include equipment such as BOP elements and lubricator O-rings.

IRP The well operator should ensure that records are kept that identify the elastomer materials in use for first-line well pressure control seals.

These records are important because there are no standard markings on most elastomeric seals to indicate the elastomer material.

21.9 Operations

21.9.1 Personnel Requirements

Coiled tubing operations require personnel with specific skills and competencies.

IRP The Coiled Tubing Supervisor should have a Coiled Tubing Well Servicing BOP ticket.

Refer to IRP 07: Competencies for Critical Roles in Drilling and Completions for information about determining critical roles then defining and evaluating competency for those critical roles. The CT Shift Supervisor or Senior Operator will likely meet the criteria for a critical role as outlined in IRP 07.

21.9.1.1 **Welder Qualifications**

IRP All welds in a coiled tubing string should be performed as follows:

- By a welder qualified in accordance with ASME Section IX (or equivalent).
- As per a WPS that has been qualified in accordance with ASME Section IX (or equivalent).
- By a welder and per a weld procedure qualified by the tubing manufacturer or with the procedure qualification record (PQR) performed on actual coiled tubing specimens.

21.9.1.2 **Experience Required for Critical Sour Operations**

IRP Any person directly involved in critical sour operations shall comply with IRP 02: Completing and Servicing Critical Sour Wells.

IRP Any individual operating the coiled tubing unit for critical sour wells shall have the well servicing blowout prevention certificate appropriate to the pressure category.

> **Note:** Any person who is at the controls of the coiled tubing unit is considered to be operating the unit.

IRP Coiled Tubing Supervisors shall be verified as competent for critical sour operations by their employer prior to performing service work on a critical sour well.

21.9.2 Pre-Rig Up

IRP Before rigging up any coiled tubing equipment on site the operating company and service company representatives shall review the equipment service log and ensure the following:

- The coiled tubing pipe to be used has sufficient serviceability to safely complete the job with a reasonable contingency factor.
- The coiled tubing string used can complete the job within operating limits (e.g., tensile strength, burst, collapse, torsional yield, etc.).
- The three-year BOP equipment certification has been completed (this includes all riser, lubricator, flow spools, cross-overs, strippers, etc., from the wellhead to the upper stripper).
- The accumulator specifications are available and accumulator sizing calculations have been performed.
- All equipment, including the coiled tubing pipe and BOP system, has been checked for compatibility with the formation fluids and treating fluids.
- If the shear ram is installed, it is capable of severing the coiled tubing pipe and any internal/external hardware being used (e.g., wireline-installed coiled tubing).
- For cold weather operations, consideration has been given to heating (or other appropriate actions) of the BOPs to ensure that the response time and sealing efficiency is satisfactory.

For critical sour operations inspection/testing requirements for the coiled tubing see 21.5.6.2 Full-Length NDE of Coiled Tubing Strings.

IRP The operating company representative shall provide a documented site-specific orientation to the service company representatives before starting operations. Items to be reviewed shall include the following:

- General safety issues
- Identification of any hazards on location
- Muster stations
- Egress routes

IRP The operating company and service company shall review the well parameters including, but not limited to, the following:

- Asphaltenes and waxes
- Condensate
- Depth
- Formation or treatment fluids

- Gas composition (especially air, H_2S and CO_2 concentrations)
- Hydrate formation potential
- Emergency response plan (if required)
- Scales (e.g., Iron sulphide, naturally occurring radioactive material (NORM) and others)
- Pressures
- Relevant well equipment and detail (e.g., trajectory, ID restrictions, etc.)
- Salinity of produced water
- Wind direction

IRP The operating company and service company shall review proposed equipment layout and spacing requirements recognizing all regulatory requirements. See IRP 20: Wellsite Design Spacing Recommendations.

IRP Including a landing nipple at the bottom of the string should be considered when running velocity strings.

An isolation dart can then be landed prior to pulling the string to minimize the possibility of a release should the string part above the well control equipment on recovery. This is strongly recommended on sour wells.

21.9.3 Rig Up

IRP A safety/operations meeting shall be held with all on-site personnel to discuss the following:

- Pressure testing
- Detailed operations to be performed
- Delegation of responsibilities
- BOP Drill requirements
- Emergency response plans
- Other operational or site-specific considerations

IRP All hydraulic lines, testing lines and kill lines shall be organized and kept tidy so they prevent interference with an emergency evacuation of the area.

IRP All equipment attached to the wellhead shall be adequately supported to limit transverse movement.

IRP Factors affecting crane operations should be considered (e.g., injector height, equipment weight and wind conditions).

IRP Stabilizing guy lines should be installed to rig anchors or a secure anchor point as deemed necessary by the rig up geometry.

IRP If liquid CO_2 is to be pumped, contingency plans shall be in place to deal with ice plugs in the surface piping (e.g., treating iron, coiled tubing).

IRP All coiled tubing well servicing equipment shall be bonded and grounded as per local jurisdictional regulations.

See IRP 08: Pumping Flammable Fluids, STANDATA CEC-10 and local jurisdictional regulations for more detail about bonding and grounding.

21.9.4 Equipment Records

Equipment records are records detailing information about the history of the equipment used during coiled tubing operations.

IRP A coiled tubing contractor shall have a pipe management system ensuring that a program is in place using a records log to predict when a coiled tubing pipe shall be removed from service.

IRP Records should be kept of the following:

- All operations conducted with the coiled tubing pipe being used.
- Fluid types and/or gases pumped.
- Depth run into the well and any repetitively cycling.

See 21.5.9.2 Post-Production Records and 21.5.11 String-Life Management System for further details.

21.9.5 Operating Practices

IRP In the planning phase of every operation, consideration shall be given to the possibility of air already being in the system or the introduction of air into the system during the operation.

IRP The coiled tubing unit shall not be left unattended while the lubricator or injector head assembly is connected to the wellhead.

IRP A pull test shall be performed on the coiled tubing pipe to BHA connection before running into the well and the intensity of the pull shall be based on the expected operational requirements.

IRP Coiled tubing pipe shall not exceed operating limits while in the hole.

IRP Factors such as differential pressure across coiled tubing pipe and axial load should be taken into consideration. These accumulative factors affect total stress level on the coiled tubing pipe.

IRP The following procedures shall be considered to bring the well under control in the event of a serious wellhead leak between the coiled tubing BOP stack and the master valve:

1. Ensure everyone on location is safe.
2. Evaluate if the coiled tubing can be pulled from the hole so the master valve can be closed to bring the well under control.
3. Evaluate if the well can be safely killed and brought under control.

IRP The following procedures should be considered if the procedures above cannot be performed:

1. Identify the depth of the bottom portion of the coiled tubing pipe.
2. Pull the bottom of the coiled tubing pipe high enough in the vertical portion of the hole to ensure that when the coiled tubing pipe is cut the top of the coil will fall below the lowest master valve.
3. Activate the slip rams.
4. Ensure tension is pulled into the coiled tubing pipe above the slip rams then activate the shear rams and shear the pipe.
5. Open the slip rams and allow the coiled tubing pipe to fall below the lower master valve.
6. Shut in Master Valve and secure the well.

IRP When performing a BOP Drill the slip rams should not be closed on the coiled tubing as this will add stress risers that could lead to premature failure of the coiled tubing in the hole. This applies to the BOP Drill only. In emergency situations the slip rams should be closed if the situation merits it.

Note: Stress risers will make the coiled string significantly more susceptible to failure in sour gas environments.

21.9.6 Bottomhole Assemblies

IRP When working in sour conditions all parts of the BHA from the end connector down to the check valves and all load bearing parts should meet the requirements of NACE MR0175/ISO 15156 or have an appropriate inhibitor applied.

IRP **When working on critical sour wells all parts of the BHA from the end connector down to the check valves and all load bearing parts shall meet the requirements of NACE MR0175/ISO 15156.**

Appendix A: Revision Log

Edition 3

Edition 3 of IRP 21 was a full scope review of all sections of the document.

Editions 1 and 2 of IRP 21 included recommended practices for coiled tubing drilling operations (both underbalanced and overbalanced). During the review for Edition 3 DACC decided that the drilling sections of the document would be removed. Additional revisions are summarized in Table 7.

Table 7. Edition 3 Revisions

Change	Section(s)	Description
Reorganization of information		• Some of the sections and subsections were reorganized for clarity and flow. • Priority for beginning sections of the document was to define pressure and well control requirements • Personnel requirements, health and safety etc. moved to 21.9 Operations
Remove information not specific to coiled tubing operations		• Throughout document removed some content that was generic to all well servicing operations and not specific to coiled tubing. This information is assumed to be part of standard operating procedures for the operator and/or service provider. • Removed content comparing coiled tubing to jointed pipe operations.
Introduction Added	21.1	• Information pulled from scope and background.
Fracturing with Coiled Tubing information added	21.2.3	• Recommendations specific to fracturing with coiled tubing incorporated into planning section

Change	Section(s)	Description

Well Control Equipment	21.3	• All information about well control equipment organized into this section and reviewed for accuracy.
		• Information about MAIP included
		• Information about Well Control Components as Barriers added (21.3.2)
		• Pressure categories modified to reflect Canadian operations rather than API (Table 3).
		  ○ Number of complete and annular barriers identified
		  ○ Kill margin, recommended working pressures and sweet/sour designation removed. Sour considerations now IRP statements under table.
		  ○ Category 0 renamed to 1 and remainder adjusted to reflect new MSASP ranges
		  ○ IRP statements throughout document revised, where applicable, to match revised pressure categories.
		• Minimum required functions by pressure category (Table 4) revised to simplify and match categories used in Table 3.
		• Removed pros and cons of flow point positioning (21.3.7) and makes more generic recommendations.
		• Added pressure testing (21.3.12) and function testing (21.3.13) requirements to this section.

Accumulator Equipment	21.4	• Updated diagram • Reviewed and updated content including adjusting to match new pressure categories and reflecting equipment spacing requirements outlined in AER D037: Service Rig Inspection Manual.
Coiled Tubing Specifications	21.5	• Renamed from Pipe Specifications and reviewed for accuracy. • Removed reference to Appendix B and replace with API 5ST. • Removed table of grades and direct reader to manufacturer specification for strength detail. • In Chemical composition removed limits table and referenced NACE MR0175/ISO 15156. • Removed table of Drift/Gauge ball diameters and refer to manufacturer specification instead. • For string life management, added retirement criteria for base tubing and removed tables for fatigue limits for base tubing and welds to replace with manufacturer specifications.

Change	Section(s)	Description
Fluids and Circulating Systems	21.6	• Section previously identified that additional information was for critical sour operations. Committee felt these applied to all sour or in some cases all well servicing operations not just critical sour and cleaned up wording as accordingly. • Remove prescriptive content from use of air section and recommended referencing the Fire and Explosion Hazard Management Guideline and IRP 22 section on Air Drilling for more information. Refer to local jurisdictional regulations for requirements.
QA for Well Pressure Control Equipment	21.7	• Cleaned up to be consistent with IRP 05: Minimum Wellhead Requirements around API monograms and quality programs. This included removing the minimum quality control measures, NDE test methods and destructive test methods sections. • Added sour requirements.
Well Servicing Operations	21.9	• Moved much content from original planning section here and reviewed. • Personnel Requirements o Removed table of certifications and training as this is up to service provider and operator. Reference IRP 07: Competencies for Critical Roles in Drilling and Completions instead. o Updated welder requirements to be consistent across all pressure categories. • Pressure testing information moved to 21.3.12 (Well Control section).
NDE of Coiled Tubing Strings	Appendix B	• Removed
Glossary	Appendix B	• Updated with terminology used in the document and merged with Acronyms and Abbreviations.
References	Appendix C	• Reviewed for accuracy and updated

The following individuals helped develop edition 3 of IRP 21 through a subcommittee of DACC.

Table 8. Edition 3 Development Committee

Name	Company	Organization Represented
Adam Alvis (co-chair)	Balanced Energy Oilfield Services Inc.	PSAC
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Edition 2

The 2016 revision for Edition 2 was a limited scope review of IRP 21 and made the modifications listed in Table 9.

Table 9. Edition 2 Revisions

Change	Section(s)	Description
Reformat to current DACC Template and Style Guide	All	Document reformatted to match the current DACC style guide (2015 version). Key updates include: • Formatting IRP statements and using range of obligation words in all IRP statements (must, shall, should). • All metric UOM rounded to two decimal places • All metric measurements shown before imperial (where present). The exception is where items are manufactured in imperial units – then imperial comes first.
Editorial Review	All	• Consistent wording, terminology, structure • Active voice • Merging related IRPs into one bulleted list to reduce bolding • Cleanup/numbering of headings • Update references to current versions
Definitions of Well Servicing Pressure Categories	21.1.2.1, All	• Updated the generic set of Well Servicing Pressure Categories that encompasses requirements from all jurisdictions and then uses those consistently throughout the IRP • Bring IRP classes into alignment with global API Standards • Use new categories in remainder of document
Update well control equipment configurations requirements	21.2.3	• Bring into alignment with the global API standard • Updated diagrams • New table of equipment (Table 15)
Update Pressure testing IRPs to use MSAP/MAOP rather than SITHP	21.7.3	• Adjusted to reflect new pressure categories and calculation methods

The following individuals helped develop edition 3 of IRP 21 through a subcommittee of DACC.

Table 10. Edition 2 Development Committee

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Edition 1

IRP 21 Edition 1 was sanctioned as a new IRP in September of 2010.

The following individuals helped develop edition 1 of IRP 21 through a subcommittee of DACC.

Table 11. Edition 1 Development Committee

Name	Company	Organization Represented
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Many more individuals significantly contributed to the technical task groups. The committee would also like to express its appreciation to the following individuals: Marv Clifton, Scott Davis, Steve Glanville, Gerard Dirk, Dennis High, Bernie Luft, John Martin, Harold Miller, Clarke Moir, Hal Morris, Brian Ness, Neil Purslow, Scott Quigley, Marc Ranks, Bruce Reichert, Ron Sanders, Matt Schmitz, Karol Sklarz, Paula Steele, Jack Thacker, Terry Wheaton, Ken Willis and Nicholas Zaglaris.

Appendix B: Glossary

The following are defined from an IRP 21 perspective.

ADI Automated Dimensional Inspection

AER Alberta Energy Regulator

API American Petroleum Institute

ASME American Society of Mechanical Engineers

ASNT American Society for Nondestructive Testing

ASTM American Society of Testing and Materials

Barrier A coiled tubing well control element that is a tested mechanical device, or combination of tested mechanical devices, capable of preventing uncontrolled flow of wellbore effluents to the surface. See 21.3.2 Well Control Components as Barriers for more information about the annular and complete barriers referenced in this IRP.

BCOGC British Columbia Oil and Gas Commission

BHA Bottomhole Assembly

Blanking Element A well control element that provides a pressure seal against an open wellbore. This would typically include a blind ram, valve or other similar technology.

BOP Blowout Preventer

Calibration Comparison and adjustment to a standard of known accuracy.

CAOEC Canadian Association of Energy Contractors

Corrosion The destruction of metal by chemical or electrochemical means. Potential agents for initiating corrosion include carbon dioxide, hydrogen sulphide, chlorides and oxygen. All of these can be introduced into the circulating system during wellbore or surface circulation of the circulating media. Corrosion results in pitting, embrittlement, stress cracking and black sulphide coating. Factors that affect corrosion rates include pressure, temperature and pH.

CAPP Canadian Association of Petroleum Producers

CMTR Certified Material Test Reports

CO_2 Carbon Dioxide

Coiled Tubing String-Life Management System A manual tracking or computer-based modelling system for predicting the remaining working life of a coiled tubing string.

Critical Sour Well/Special Sour Well Each meets the conditions for release rate and proximity defined by the applicable jurisdictional regulator. These terms refer to the current definition from the AER (critical sour) and BCOGC (Class C/Special Sour).

CT Coiled Tubing

DACC Drilling and Completions Committee

Discharge Lines The treatment line from downstream of the discharge of the high pressure pump.

DMDS Dimethyl Disulphide

EDM Electron Discharge Machined

Elastomer An elastomer is 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**.**

EMI Electromagnetic Inspection'

Erosion The wear of material by mechanical means. Solids contained in the produced fluids stream typically result in erosion of surface flow control equipment. Factors that affect erosion rates include concentration, type and size of solids and transport velocity**.**

ESD Emergency Shut Down (Valve)

H_2S Hydrogen Sulphide

HAZ Heat-affected Zone

HE Hydrogen Embrittlement

HIC Hydrogen Induced Cracking

HCl Hydrochloric Acid

HCR Hydraulically Controlled Remote (Valve)

HRC Rockwell "C" Hardness

Hydrostatic Proof-Testing of Coiled Tubing Strings Pressure tests performed on a string of coiled tubing at a facility (manufacturer, end user, etc.). These tests typically follow any string maintenance being performed on the coil. It is separate from any subsequent testing performed during rig-up or other operations at a wellsite.

ID Inside Diameter

IQI Image Quality Indication

Iron Management System The purpose of iron management systems is to ensure the integrity of the iron. They typically consider the potential for degradation of materials (e.g., erosion, corrosion, chemical/environmental degradation, temperature considerations, stress fatigue), pressure testing, material thickness testing, non-destructive testing, proper maintenance of materials and proper identification and tracking of information about the iron (e.g., in-service dates, inspections, manufacturer specifications). Refer to manufacturer recommendations for more detail.

IRP Industry Recommended Practice

ISO International Standards Organization

LCM Lost Circulation Material

LPI Liquid Penetrant Inspection

Maximum Allowable Operating Pressure (MAOP) For a given piece of equipment, the highest calculated pressure that a given equipment component will be subjected to during the execution of the prescribed service and/or during a contingency operation.

Maximum Anticipated Surface Pressure (MASP) The highest pressure predicted to be encountered at the surface of a well. This pressure prediction should be based upon formation pressure minus a wellbore filled with native formation fluid at current conditions. If formation fluid is unknown, this pressure prediction should be based upon formation pressure minus a wellbore filled with dry gas from the surface to the completion interval.

MPI Magnetic Particle Inspection

MQP Manufacturing Quality Plan

MT Magnetic Testing

MTR Material Test Report

N_2 Nitrogen Gas

NACE National Association of Corrosion Engineers

NDE Non-destructive Examination

NORM Naturally Occurring Radioactive Material

OD Outside Diameter

OEM Original Equipment Manufacturer

Ovality The distortion on the cross-sectional profile of a coiled tubing string. The mechanical performance of oval tubing deteriorates as the degree of ovality increases. The most critical effect is the ability of the tube to resist collapse under differential pressure. String ovality limits are generally determined by the maximum diameter that can pass through the primary pressure-control equipment. In high-pressure operations, the ovality limits will generally be reduced to maintain an adequate safety margin against string collapse. (Source: SLB Oilfield Glossary).

Pipe Sealing Element A well control element that provides a pressure seal against a section of pipe of fixed diameter. This may include an annular preventer, set of fixed diameter pipe rams, stripper element or other similar technology.

Plastic Plastics (e.g., 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.

Predicted Life to Failure The fatigue life of a string calculated by a computer model where all safety limits are removed.

PPE Personal Protective Equipment

PQR Procedure Qualification Record

Predicted Working Life The fatigue life of a string calculated by a computer with a known safety factor in place.

Pressure Control 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.

Pressure Control System A pressure control system is defined as the blowout prevention system and includes all equipment from the top wellhead flange to the uppermost piece of pressure control equipment. The pressure containing system includes the BOP stack, snubbing stack, coiled tubing stack and pressure deployment system (including all bleed lines).

PSAC Petroleum Services Association of Canada

PT Penetrant Testing

QMS Quality Management System

Remanufacture Rework of original equipment manufacturer (OEM) specified dimensions or welding.

Return Line The line from the discharge from the well (flow tee or other) up to the primary choke manifold.

RT Radiographic Testing

SCC Stress Corrosion Cracking

SDS Safety Data Sheet

Shearing Element A well control element that provides a clean shear cut of the tubulars located across the element in the wellbore. As a stand-alone ram function, they provide no pressure seal and as such they are not considered to be well control devices. This would typically include a shear ram or other similar technology.

SITHP Shut-in Tubing Head Pressure

Slip Rams Ram devices designed to hold the coiled tubing securely in place in the well control stack. As a stand-alone ram function, they provide no pressure seal and as such they are not considered to be well control devices.

SMYS Specified Minimum Yield Strength

SPE Society of Petroleum Engineers

SSC Sulphide Stress Cracking

Stress Corrosion Cracking Brittle failure by cracking under combined action of tensile stress and corrosion in the presence of water and hydrogen sulphide or chloride.

String Separation A separation above the highest disconnect in the coiled tubing string. This separation may be intentional or as a result of material failure.

TDG Transportation of Dangerous Goods

Tg Gas Transition Temperature

UT Ultrasonic Shear Wave Testing

Variable Pipe Sealing Element A well control element that provides a pressure seal against sections of varying diameters. This may include an annular preventer, a set of variable pipe rams or other similar technology.

VME von Mises Equivalent

WHMIS 2015 Workplace Hazardous Materials Information System 2015 version incorporating the Globally Harmonized System of Classification and Labeling of Chemicals (GHS)

WPS Weld Procedure Specification

Appendix C: References

Alberta Regulations

These following documents are available through the Alberta Energy Regulator (www.aer.ca).

- Directive 033: Well Servicing and Completions Operations - Interim Requirement Regarding the Potential for Explosive Mixtures and Ignition in Wells
- Directive 036: Drilling Blowout Prevention Requirements and Procedures
- Directive 037: Service Rig Inspection Manual
- Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting
- Alberta Oil and Gas Conservation Regulations and Rules

API

The following document is available through www.API.org:

- API Spec 5ST: Specification for Coiled Tubing-U.S. Customary and SI Units, First Edition. 2020.
- API Spec 6A: Specification for Wellhead and Christmas Tree Equipment, Twenty-first Edition. 2019.
- API Purchasing Guideline API Specification 6A 20th Edition, October 2010. R1 20120429.
- API Spec Q1 Quality Program1: Specification for Quality Management System Requirements for Manufacturing Organizations for the Petroleum and Natural Gas Industry, Includes Errata (February 2014), Errata 2, 9th Edition. March 2014.

ASME

The following documents are available from www.ASME.org:

- ASME Boiler and Pressure Vessel Code, Section V: Nondestructive Examination. July 2015.
- ASME Boiler and Pressure Vessel Code, Section IX: Welding and Brazing Qualifications. July 2015.

ASNT

The following document is available from www.ASNT.org:

- SNT-TC-1A (2011) Personnel Qualification and Certification in Nondestructive Testing

ASTM

The following documents are available through ASTM (www.astm.org):

- ASTM A370: ASTM A370 - 15 Standard Test Methods and Definitions for Mechanical Testing of Steel Products
- ASTM A450/440M: ASTM A450/A450M - 15 Standard Specification for General Requirements for Carbon and Low Alloy Steel Tubes
- ASTM D1053: ASTM D1053 – 92A Standard Test Methods Rubber Property - Stiffening at Low Temperatures: Flexible Polymers and Coated Fabrics. 2012.
- ASTM D1329: ASTM D1329 – 08 Standard Test Method for Evaluating Rubber Property - Retraction at Lower Temperatures (TR Test)
- ASTM E10: ASTM E10-15 Standard Test Method for Brinell Hardness of Metallic Materials Volume 03.01
- ASTM E1030/E1030M: ASTM E1030/E1030M - 15 Standard Test Method for Radiographic Examination of Metallic Castings Volume 03.03
- ASTM E1032: ASTM E1032 - 12 Standard Test Method for Radiographic Examination of Weldments Volume 03.03
- ASTM E140: ASTM E140 – 12be1 Standard Hardness Conversion Tables for Metals Relationship Among Brinell Hardness, Vickers Hardness, Rockwell Hardness, Superficial Hardness, Knoop Hardness, and Scleroscope Hardness Volume 03.01
- ASTM E164: ASTM E164 - 13 Standard Practice for Contact Ultrasonic Testing of Weldments Volume 03.03
- ASTM E165/165M: ASTM E165 - 12 Standard Practice for Liquid Penetrant Examination for General Industry Volume 03.03
- ASTM E18: ASTM E18 - 15 Standard Test Methods for Rockwell Hardness of Metallic Materials Volume 03.01
- ASTM E273: ASTM E173-15 Standard Practice for Ultrasonic Testing of the Weld Zone of Welded Pipe and Tubing Volume 03.03
- ASTM E309: ASTM E309-11 Standard Practice for Eddy-Current Examination of Steel Tubular Products Using Magnetic Saturation Volume 03.03
- ASTM E384: ASTM E384 – 11e1 Standard Test Method for Knoop and Vickers Hardness of Materials Volume 03.01

- ASTM E570: ASTM E570-15 Standard Practice for Flux Leakage Examination of Ferromagnetic Steel Tubular Products Volume 03.03
- ASTM E709: ASTM E709-15 Standard Guide for Magnetic Particle Testing Volume 03.03
- ASTM E751/E751M: ASTM E751/E751M – 12 Standard Practice for Acoustic Emission Monitoring During Resistance Spot-Welding Volume 03.03
- ASTM E8/E8M: ASTM E8/E8M – 15A Standard Test Methods for Tension Testing of Metallic Materials Volume 03.01
- ASTM E94: ASTM E94 – 04 (2010) Standard Guide for Radiographic Examination Volume 03.03

DACC Resources

The following documents are available from Energy Safety Canada (www.energysafetycanada.com):

- Energy Safety Canada Fire and Explosion Hazard Management Guideline
- Energy Safety Canada Lease Lighting Guideline
- IRP 02: Completing and Servicing Sour Wells
- IRP 04: Well Testing and Fluid Handling
- IRP 07: Competencies for Critical Roles in Drilling and Completions
- IRP 08: Pumping of Flammable Fluids
- IRP 14: Non-Water Based Drilling and Completion/Well Servicing Fluids
- IRP 20: Wellsite Design Spacing Recommendations
- IRP 22: UBD/MPD/RMD Operations

General Safety References

Table 12. General Safety Resources

Resource	Description
IRP 02: Completing and Servicing Sour Wells	Safety requirements associated with critical sour wells
IRP 08: Pumping of Flammable Fluids	Safety requirements associated with pumping flammable fluids under pressure Bonding and Grounding requirements
Jurisdictional legislation, regulations and codes	• Work wear requirements • Facial hair • Operations involving explosives • Lease lighting • Emergency washing facilities • Fire extinguishers

Resource	Description
	• Breathing apparatus • Emergency vehicles • Crane/boom truck operator requirements • Noise restrictions • Hours of service • Other recommended equipment • Other general safety requirements
STANDATA Canadian Electrical Code Jurisdictional legislation	Electrical Bonding and Grounding
Energy Safety Canada Lease Lighting Guideline	Lease lighting
Jurisdictional regulations Worksafe Saskatchewan/Government of Saskatchewan - Thermal Conditions: Hot and Cold Conditions at Work Alberta OH&S – Best Practice Working Safely in Heat and Cold WorkSafe BC – Guidelines part 7 – Division 4 – Thermal Exposure	Working in hot/cold weather

NACE

The following documents are available through NACE (www.nace.org):

- NACE TM0187 2011: Standard Test Method for Evaluating Elastomeric Materials in Sour Gas Environments
- NACE TM0296-2014: Standard Test Method for Evaluating Elastomeric Materials in Sour Liquid Environments
- NACE Standard MR0175/ISO 15156: Materials for use in H_2S-containing Environments in oil and gas production

Other References

Other references include the following:

- Alberta OHS publication GS006: Best Practice – Working Safely in the Heat and Cold (available through work.alberta.ca under Occupational Health and Safety, Publications, Education and Promotion).

- BC Oil and Gas Commission Drilling and Production Regulations can be found on the Legislation page of the BCOGC website.

- Manitoba Drilling and Production Regulations can be found on the Government of Manitoba Website under the Manitoba Mineral Resources Acts and Regulations page.
- Saskatchewan regulations are found in Saskatchewan Oil and Gas Conservation Regulations (OGCR) and can be found on the Government of Saskatchewan Website under the Publications Centre for the Queens Printer. Publication name is the Oil and Gas Conservation Regulations.
- SPE Paper 38412: Determining the Mechanical Properties of Coiled Tubing