COILED TUBING OPERATIONS

AN INDUSTRY RECOMMENDED PRACTICE (IRP) FOR THE CANADIAN OIL AND GAS INDUSTRY

VOLUME 21 – 2010
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PREFACE

PURPOSE

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

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

Existing OHS and other jurisdictional regulations must be consulted. The inclusion of extensive quotes from, or reference to, these regulations has been minimized to avoid potential conflict when the IRP may quote from or refer to out of date regulation.

AUDIENCE

The intended audience of this document includes oil and gas company engineers, field consultants, coiled tubing personnel, drilling and service rig personnel, well testing and fluid hauling personnel, other specialized well services personnel, and regulatory bodies.

SCOPE AND LIMITATIONS

This IRP applies to all coiled tubing drilling and coiled tubing well servicing operations performed in a wellbore. It presents recommendations in Section 4: Recommendations on Fluids and Circulating Systems within a tank-to-tank concept and covers both overbalanced and underbalanced operations. The well control equipment sections of the IRP were developed with the consideration that the hydrostatic head of the fluid column may no longer be the primary method of well control. In underbalanced operations, the well control equipment is considered the primary well control mechanism preventing the escape of wellbore fluids and ensuring the safety of personnel on site.

These recommendations are considered to be the minimum recommended practices and best practices necessary to carry out operations in a manner that protects people (including the public and workers) and the environment. The IRP includes pertinent information about CT operations, including recommendations regarding the following:

1. CT operations planning,
2. CT BOP stacks and accumulators,
3. CT pipe,
4. fluids and circulating systems,
5. well-pressure-containing equipment,
6. elastomeric seals,
7. CT operations for well servicing, and
8. CT operations for drilling.

IRP 21 refers to other pertinent standards where appropriate, and provides information on how to access them. A full list of the documents referred to in this IRP is provided in Appendix A.

This IRP was developed based on existing documentation and regulations in Alberta. In other regulatory jurisdictions, follow their IRPs in conjunction with their applicable regulations. This IRP recognizes that other procedures and practices as well as new technological developments may be equally effective in promoting safety and efficiency.

Specifically excluded from this IRP are capillary tubing operations and CT operations conducted on pipelines and other non-wellbore operations.

**Recommended Practices Versus Best Practices**

Within the body of this document, any accepted industry practices or provisions align with the words “shall”/“must” and are signified visually by a black triangular bullet (▲). Any recommendations or actions that are advised align with the word “should” are signified by a white triangular bullet (▶). Paragraphs in a standard format provide supporting information.

**Range of Obligation Specified in This IRP**

This IRP uses the following terms to identify the various levels of obligation or requirement related to coiled tubing operations:

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Every effort has been made to ensure the accuracy of the data but readers must consult the appropriate regulatory documents to ensure compliance.

**Revision Process**

Industry recommended practices (IRPs) are developed by industry for industry with the involvement of both the upstream petroleum industry and relevant regulators.
IRPs provide a unique resource outside of direct regulatory intervention.

This is the first edition of IRP 21. Technical issues, new equipment, and revised procedures (as well as revisions to reference specifications, standards, and other IRPs used in the development of this IRP) brought forward to the Drilling and Completions Committee (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 specific process for the creation and revision of IRPs, visit the Enform website at www.enform.ca.

SANCTION

The following organizations have sanctioned this document:
- Canadian Association of Oilwell Drilling Contractors
- Canadian Association of Petroleum Producers
- Energy Resources Conservation Board
- Intervention and Coiled Tubing Association
- National Energy Board
- Oil and Gas Commission
- Petroleum Services Association of Canada
- Saskatchewan Energy Resources
- Small Explorers and Producers Association of Canada
- WorkSafeBC

Alberta Employment and Immigration has reviewed IRP Vol. 21 - Coiled Tubing Operations and, as of the date of adoption, finds the set out information meets occupational health and safety legislative requirements. Users are cautioned that IRP Vol. 21 - Coiled Tubing Operations is a guideline only and that proper compliance requires a customized program that addresses the conditions of the specific worksite.

Saskatchewan Occupational Health and Safety has reviewed IRP Vol. 21 - Coiled Tubing Operations and, as of the date of adoption, finds the set out information meets occupational health and safety legislative requirements. Users are cautioned that IRP Vol. 21 - Coiled Tubing Operations is a guideline only and that proper compliance requires a customized program that addresses the conditions of the specific worksite.

ACKNOWLEDGEMENTS

The following individuals helped develop this IRP through a subcommittee of DACC. They represent a wide cross-section of personnel and provided forward-thinking views, as well as insightful recommendations to address the challenges and needs of CT operations. We are grateful for each participant’s efforts. We also wish to
acknowledge the support of the employers of individual committee members.

**IRP 21 Development Committee**

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<td>ICoTA/PSAC</td>
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<tr>
<td>John Butala</td>
<td>BP Canada Energy Company</td>
<td>CAPP</td>
</tr>
<tr>
<td>Francois Cantaloube</td>
<td>Schlumberger Canada Limited</td>
<td>ICoTA/PSAC</td>
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<tr>
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<td>Paul Elkins</td>
<td>Alberta Human Resources and Employment</td>
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<tr>
<td>Manuel Macias</td>
<td>Enform</td>
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<tr>
<td>John Mayall</td>
<td>Alberta Energy Resources Conservation Board</td>
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<tr>
<td>Tom Murphy</td>
<td>Shell Canada Energy</td>
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<tr>
<td>Kirby Nicholson</td>
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<tr>
<td>Doug Pipchuk</td>
<td>Schlumberger Canada Limited</td>
<td>ICoTA/PSAC</td>
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<td>Paul Saulnier</td>
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<tr>
<td>Kevin Schmigel</td>
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<td>Murray Sunstrum</td>
<td>Enform</td>
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<td>ICoTA</td>
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<td>Roch Romanson</td>
<td>Halliburton Canada</td>
<td>ICoTA/PSAC</td>
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<td>CAPP</td>
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</tbody>
</table>

**Other Contributors**

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.
DESCRIPTION OF CT OPERATIONS

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

1. Pumping 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), and
   - removing wax, hydrocarbon, or hydrate plugs.

2. 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),
   - sliding sleeve operation,
   - running a completion,
   - performing straddles for zonal isolation, and
   - drilling.

EQUIPMENT USED IN CT OPERATIONS

In this IRP, coiled tubing is defined as continuously manufactured steel tubular product spooled onto a take-up reel. Coiled tubing equipment includes the reel, injector head, control cabin, and power pack. They are designed and required to
perform these functions:

- reel – used to store and transport the coiled tubing,
- injector head – used to provide the surface drive force to run and retrieve the coiled tubing,
- control cabin – used by the equipment operator to monitor and control the coiled tubing, and
- power pack – used to generate hydraulic and pneumatic power required to operate the coiled tubing unit.

**PERSONNEL INVOLVED DURING CT OPERATIONS**

The following crews or personnel may be involved during CT operations:

- coiled tubing crews,
- downhole tool specialists,
- drilling rig crews,
- electric line and slickline crews,
- oil company representatives,
- pumping services personnel,
- safety supervisors,
- service rig crews,
- well fracturing and stimulation crews, and
- well testing crews.
Section 1 RECOMMENDATIONS ON COILED TUBING OPERATIONS PLANNING

This section addresses the following CT operations planning topics:

1. job objectives,
2. well classification and history,
3. personnel requirements,
4. health and safety communications,
5. health and safety requirements,
6. emergency response plan (ERP),
7. equipment specifications, and
8. operational practices and procedures.

1.1 Determining Job Objectives

CT operations planning should begin with job objectives and a brief summary of the work to be done.

1.2 Reviewing Well Classification and History

Industry and regulatory bodies use well classifications for administrative purposes. However, for technical purposes, specific concentrations and the potential release rate of hydrogen sulfide dictate equipment required to do tasks safely, maintain worker health and safety, and ensure equipment integrity.

Tables 1 and 2 below summarize the current well classification systems for the purposes of this IRP as well as for the provinces of Alberta, British Columbia, Manitoba, and Saskatchewan. Different regulations, industry recommended practices, and best practices can apply for different classes of wells. For any conflict or uncertainty regarding which class to follow, follow the higher class (with the more stringent requirements).
### Table 1: Well Classification for Well Servicing Blowout Prevention

<table>
<thead>
<tr>
<th>Classification for IRP 21</th>
<th>Provincial Classifications</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Class</strong></td>
<td><strong>Description</strong></td>
</tr>
<tr>
<td>Class I</td>
<td>Reservoir pressure less than 5.5 MPa, no H₂S and: (i) is a gas well, or (ii) produces heavy oil density &gt;920 kg/m³, GOR &lt; 70 sm³/m³ and produces by primary recovery or is included in a waterflood scheme.</td>
</tr>
<tr>
<td>Class II</td>
<td>Pressure rating of casing flange ≤ 21,000 kPa and H₂S &lt; 10 moles/kilomole</td>
</tr>
<tr>
<td>Class III</td>
<td>Pressure rating of casing flange is (i) &gt; 21,000 kPa, or (ii) ≤ 21,000 kPa and H₂S ≥ 10 moles/kilomole</td>
</tr>
<tr>
<td>Class IV</td>
<td>Based on potential H₂S discharge rate and proximity of public as per ERCB and B.C. Oil and Gas Commission definition</td>
</tr>
</tbody>
</table>

*NOTE: A Class IIA well in Alberta is a well that produces heavy oil density > 920 kg/m³, GOR < 70 sm³/m³, a maximum H₂S release rate of < 0.001 m³/second, and an expected BH pressure of < 21,000 kPa.*
Table 2: Well Classification for Drilling Blowout Prevention

<table>
<thead>
<tr>
<th>Classification for IRP 21</th>
<th>Provincial Classifications</th>
</tr>
</thead>
<tbody>
<tr>
<td>Class</td>
<td>Description</td>
</tr>
<tr>
<td>Class I</td>
<td>A well in which no surface casing is set.</td>
</tr>
<tr>
<td>Class II</td>
<td>A well in which the true vertical depth is less than or equal to 750 m.</td>
</tr>
<tr>
<td>Class III</td>
<td>A well in which the true vertical depth is greater than 750 m and less than or equal to 1,800 m.</td>
</tr>
<tr>
<td>Class IV</td>
<td>A well in which the true vertical depth is greater than 1,800 m and less than or equal to 3,600 m.</td>
</tr>
<tr>
<td>Class V</td>
<td>A well in which the true vertical depth is greater than 3,600 m and less than or equal to 6,000 m.</td>
</tr>
<tr>
<td>Class VI</td>
<td>A well in which the true vertical depth is greater than 6,000 m.</td>
</tr>
</tbody>
</table>

*NOTES:*
1. For Manitoba, the classification changes at the Devonian Three Forks Formation. That formation is estimated to be at about 1,000 m.
2. For wells drilled in British Columbia consult Oil and Gas Commissions Directives/Regulations on well control requirements. The above table is a general comparison.

▷ Well class and history should be reviewed as part of operations planning.

▷ Well class and previous and potential problems should be identified and concisely summarized as background information for wellsite personnel. Relevant well data would include the following:
  - the data listed in Section 8.1.2: General Requirements of this IRP with the exception of wind direction,
  - a history of work carried out on the well,
  - current well conditions, and
  - any operation that may have introduced air, oxidizing agents, etc., into the system.
1.3 **ESTABLISHING PERSONNEL REQUIREMENTS**

1.3.1 **REQUIREMENT TO DEMONSTRATE COMPETENCE**

- The following personnel shall be able to demonstrate their competence that they fully understand and handle their individual responsibilities:
  - crew members;
  - coiled tubing shift supervisors and coiled tubing supervisors (note that for drilling operations, a coiled tubing shift supervisor is equivalent to a driller and a coiled tubing supervisor is equivalent to a rig manager);
  - wellsite supervisors;
  - prime contractor representatives. For further details on supervision, prime contractor requirements, etc, consult the appropriate provincial legislation.

- Support personnel (such as completion engineers and superintendents) shall be familiar with and have taken into account recommended practices and best practices applicable to the operation being conducted.

- IRP 7: Standards for Wellsite Supervision of Drilling, Completion and Workovers should be consulted for more information on this subject.

1.3.2 **REQUIREMENT FOR TRAINING / CERTIFICATES FOR WELL SERVICING OPERATIONS**

Table 3 below depicts in a matrix the training/certificates required or optional for CT crew members, shift supervisors, supervisors, and wellsite supervisors for well servicing operations.

Confined Space and Fall Protection certificates are mandatory for anyone carrying out such activities.

This table is not intended to provide a complete list of training and certification. Specific tasks and/or jurisdictional legislation may require additional training or certification.
Table 3: Training/Certificates Matrix for Well Servicing Operations

<table>
<thead>
<tr>
<th></th>
<th>*H2S Alive®</th>
<th>TDG</th>
<th>WHMIS</th>
<th>First Aid</th>
<th>Confined Space Entry (Pre-Entry Portion)</th>
<th>Fall Protection</th>
<th>Coiled Tubing Well Service Blowout Prevention</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>CT crew member</strong></td>
<td>M</td>
<td>M</td>
<td>M</td>
<td>O</td>
<td>O</td>
<td>O</td>
<td>O – with exception in Section 1.3.5</td>
</tr>
<tr>
<td><strong>CT shift supervisor / senior operator</strong></td>
<td>M</td>
<td>M</td>
<td>M</td>
<td>M</td>
<td>M</td>
<td>M</td>
<td>M</td>
</tr>
</tbody>
</table>

*or equivalent industry-recognized certification

M=mandatory

O=optional

1 The CT shift supervisor /senior operator classification is intended to indicate an either/or requirement, not both.

Wellsite Supervisor requirements are addressed in IRP 7: Standards for Wellsite Supervision of Drilling, Completion and Workovers. For Well Servicing operations Wellsite Supervisor shall have Coiled Tubing Well Servicing BOP ticket.

1.3.3 **Requirement for Training / Certificates for Drilling Operations**

Table 4 below depicts in a matrix the training/certificates required or optional for CT crew members, shift supervisors, supervisors, and wellsite supervisors.

Confined Space and Fall Protection certificates are mandatory for anyone carrying out such activities.

This table is not intended to provide a complete list of training and certification. Specific tasks and/or jurisdictional legislation may require additional training or certification.
Table 4: Training/Certificates Matrix for Drilling Operations

<table>
<thead>
<tr>
<th></th>
<th>*H2S Alive®</th>
<th>TDG</th>
<th>WHMIS</th>
<th>First Aid</th>
<th>Confined Space Entry (Pre-Entry Portion)</th>
<th>Fall Protection</th>
<th>First Line Supervisor’s BOP Certification</th>
<th>Second Line Supervisor’s Well Control Certification</th>
</tr>
</thead>
<tbody>
<tr>
<td>CT crew member</td>
<td>M</td>
<td>M</td>
<td>M</td>
<td>O</td>
<td>O</td>
<td>O</td>
<td>O – with exception in Section 1.3.5</td>
<td>N/A</td>
</tr>
<tr>
<td>CT shift supervisor/driller</td>
<td>M</td>
<td>M</td>
<td>M</td>
<td>M</td>
<td>M</td>
<td>M</td>
<td>M – either first or second line</td>
<td></td>
</tr>
<tr>
<td>CT supervisor/rig manager</td>
<td>M</td>
<td>M</td>
<td>M</td>
<td>M</td>
<td>M</td>
<td>M</td>
<td>N/A</td>
<td>M</td>
</tr>
</tbody>
</table>

*or equivalent industry-recognized certification  
M=mandatory  
O=optional

Wellsite Supervisor requirements are addressed in IRP 7: Standards for Wellsite Supervision of Drilling, Completion and Workovers.

1.3.4 WELDER QUALIFICATIONS

▷ All welds in a CT string proposed for operations in a well servicing Class I well should be welded as follows:

a. by a welder qualified in accordance with *ASME Section IX or equivalent*, and

b. as per a weld procedure specification (WPS) that has been qualified in accordance with *ASME Section IX or equivalent*.

▷ All welds in a CT string proposed for operations in a well servicing Class II, well servicing Class III, or Critical Sour well shall be welded as follow:

a. by a welder qualified in accordance with *ASME Section IX or equivalent*,

b. as per a WPS that has been qualified in accordance with *ASME Section IX or equivalent*, and

c. with the procedure qualification record (PQR) performed on actual CT specimens.

1.3.5 EXPERIENCE REQUIRED FOR CRITICAL SOUR OPERATIONS

▷ Any person directly involved in wellsite operations shall comply with *IRP 7: Standards for Wellsite Supervision of Drilling, Completion and Workovers* and any person directly involved in critical sour operations shall comply with either *IRP 2: Completing and Servicing Critical Sour Wells* or *IRP 6: Critical Sour Underbalanced Drilling* as well as *IRP 7: Standards for Wellsite Supervision of Drilling, Completion and Workovers*. 
For critical sour / special sour wells, any individual operating the unit (that is at the controls of the coiled tubing unit) shall have the relevant drilling/well service blowout prevention certificate.

For critical sour / special sour well servicing operations, coiled tubing supervisors shall have been involved (as coiled tubing supervisors) in five workover or completion operations while these wells were in the sour zone (that is supervised on five non-critical sour/special sour well operations while the well was in the sour zone) and work shall have been conducted on wells of similar depth and complexity.

For critical sour / special sour drilling operations, coiled tubing shift supervisors / coiled tubing supervisors shall have been involved (as coiled tubing supervisor) in five wells while these wells were in the sour zone (that is supervised on five non-critical sour / special sour well operations while the well was in the sour zone) and work shall have been conducted on wells of similar depth and complexity.

1.3.6 SUPERVISION REQUIRED

SHARED RESPONSIBILITY

The day-to-day operations on a lease are a shared responsibility between the contractor’s and operator’s representatives, but the ultimate responsibility for supervision of the well operation shall be assigned by the operator to the operator’s representative. For further details on supervision, prime contractor requirements, etc, consult the appropriate provincial legislation.

OPERATOR’S REPRESENTATIVE

The operator shall delegate a primary wellsite supervisor as having overall control in the chain of command. The primary wellsite supervisor has the overall responsibility to his company for the well and for compliance with all regulations relating to the operation of the well.

The primary wellsite supervisor shall be on site (or readily available) at all times and shall establish a chain of command and a line of communication at the wellsite.

Contractor’s Representative

The contractor’s representative has the responsibility to the operator’s representative for the operation of the rig / unit during the drilling/servicing of the well which provides for a single chain of command for the well operation.

The contractor’s representative is responsible to his or her company for the equipment and crew, and for compliance with all regulations relating to the operation of the contractor’s equipment.
SUPERVISION FOR CRITICAL SOUR UNDERBALANCED DRILLING OPERATIONS

► The primary wellsite supervisor shall be delegated by the operator as having overall control in the chain of command for critical sour underbalanced wells.

► The coiled tubing supervisor shall be available to the operation on a 24-hour call basis (and for night moves, two coiled tubing supervisors shall be available).

1.4 SPECIFYING HEALTH AND SAFETY COMMUNICATIONS

► A safety meeting shall be held with all shift personnel on location as follows:
  • before starting operations,
  • before any hazardous operation, and
  • at shift change.

1.5 DETERMINING HEALTH AND SAFETY REQUIREMENTS

1.5.1 HAZARD ASSESSMENTS

► Part of CT operations planning shall be a review of each CT operation to evaluate the hazards that operation would present. Each situation will present its own unique circumstances. Below are some identifiable hazards to consider during hazard assessment:
  • environmental factors (lease conditions, wind speed / direction, etc);
  • potential of an air / hydrocarbon mix in the wellbore, surface equipment, etc.;
  • pinch points, slips, trips, falls, and manual lifting;
  • working in the vicinity of suspended loads;
  • moving equipment;
  • high pressure areas;
  • working at height;
  • simultaneous / concurrent operations;
  • potential of naturally occurring radioactive material (NORM).

1.5.2 GENERAL SAFETY REQUIREMENTS

INFORMATION SOURCES FOR GENERAL SAFETY REQUIREMENTS

► IRP 1: Critical Sour Drilling, IRP 2: Completing and Servicing Critical Sour Wells, and IRP 6: Critical Sour Underbalanced Drilling should be consulted for information on general safety requirements and safety requirements associated with working on critical sour wells.
Recommendations on Coiled Tubing Operations Planning

Applicable legislation, regulations, and codes should be consulted for information and adhered to for the following:

- workwear requirements,
- facial hair,
- operations involving explosives,
- lease lighting,
- emergency washing facilities,
- fire extinguishers,
- breathing apparatus,
- emergency vehicles,
- crane/boom truck operator requirements,
- other recommended equipment, and
- other general safety requirements.

In addition, the following reference documents should be consulted for information and followed as required:

- for electrical bonding and grounding, refer to applicable STANDATA, Canadian Electrical Code and applicable jurisdictional legislation;
- for lease lighting, refer to IRP 23: Lease Lighting Standards;
- for working in hot / cold weather, refer to jurisdictional guides / regulations. These include, but are not limited to:
  - Thermal Conditions: Hot and Cold Conditions at Work – Government of Saskatchewan and Worksafe Saskatchewan websites
  - Best Practice Working Safely in Heat and Cold – Worksafe Alberta website
  - Guidelines Part 7 - Division 4 - Thermal Exposure – Worksafe BC website

Safety issues relating to well control are not specifically addressed in this section as they are covered elsewhere and in the Coiled Tubing Well Service Blowout Prevention course and First / Second Line Well Control Certification course mandated in Section 1.3.2: Requirement for Training / Certificates for Well Servicing Operations and Section 1.3.3: Requirement for Training / Certificates for Drilling Operations of this IRP.

1.5.3 **CT-Specific Safety Requirements**

Procedures shall be in place for, and personnel competent on location to deal with, the situations listed below.
COILED TUBING OVERPRESSURE

► If the CT string is subjected to an overstress, it shall be removed from service until an inspection and an evaluation by the appropriate service company representative has been carried out as to its suitability for use.

COILED TUBING RUN-AWAY

► Personnel shall be aware of the specific procedures to deal with situations where a loss of chain traction causes a run-away of the CT string in or out of the hole.

LOSS OF PRESSURE INTEGRITY

► Supervisors and operators shall be competent to deal with a loss of integrity of the coiled tubing, well control equipment, treating iron, and any other components of the operation.

► Personnel shall be made aware of the hazards related to a complete separation of the CT string between the gooseneck and the reel. Personnel should stay clear of all areas that may be impacted by such a separation.

PULLING COILED TUBING THROUGH STRIPPER

► When pulling out of hole, as the BHA approaches surface, the running speed should be reduced to ensure that a depth counter error will not result in pulling the coiled tubing through the stripper.

► When using a BHA of the same OD as the coiled tubing, an upset should be used in the BHA to ensure a “tag out” on the stripper.

STRIPPER ELEMENT CHANGE-OUT

► Where it is necessary to replace the elements in a stripper assembly during the operation, do the following:

1. confirm that the barriers in the well control equipment are holding,
2. mask up for sour conditions,
3. ensure appropriate monitoring devices are used (LEL, H₂S as required), and
4. ensure that a rescue plan is in place.
CRANE SAFETY

- Consult appropriate jurisdictional legislation for specific requirements.
- Criteria shall be in place to identify critical lifts.
- For critical lifts, a critical lift plan shall be prepared.
- Working in the vicinity of suspended loads shall be minimized.
- Crane shall be operated within and in accordance with manufacturers’ specifications / guidelines.
- Consideration should be given to suspending work as required by high wind speed, cold weather, or other environmental factors.

LOCK-OUTS

- Consult appropriate jurisdictional legislation for specific requirements.
- Maintenance or repair work on the injector head or reel requires lock-out procedures.
- Reels shall be physically restrained when personnel are working inside the structure.

WORKING AT HEIGHTS

The nature of CT operations requires working at heights.
- The applicable regulatory requirements shall be followed.
- A rescue plan shall be in place for personnel working at heights.

1.5.4 CRITICAL SOUR WELL SERVICING SAFETY REQUIREMENTS

For details on site safety requirements for critical sour well servicing, refer to Section 2.12 of IRP 2: Completing and Servicing Critical Sour Wells.

1.5.5 CRITICAL SOUR OVER / UNDERBALANCED DRILLING OPERATIONS PLANNING AND SAFETY REQUIREMENTS

- For details on critical sour overbalanced drilling planning requirements and site safety requirements, refer to sections 1.3 and 1.12 of IRP 1: Critical Sour Drilling.
- For details on critical sour underbalanced drilling planning requirements and site safety requirements, refer to sections 6.1 and 6.7 of IRP 6: Critical Sour Drilling.
**Underbalanced Drilling.**

1.5.6 **CRITICAL SOUR WELL INTERVENTION PLANNING REQUIREMENTS**

- For details on these planning requirements, refer to Section 2.12.4 of *IRP 2: Completing and Servicing Critical Sour Wells*.

1.6 **PREPARING EMERGENCY RESPONSE PLAN (ERP)**

- For an ERP, the prime contractor’s generic or corporate plan must be used along with any site-specific plans developed.
- Regulatory requirements must be consulted for ERP requirements and content.

1.7 **DETERMINING EQUIPMENT SPECIFICATIONS**

- Part of CT operations planning should be determining the appropriate equipment specifications and configurations required for the job, including any necessary engineering calculations, which should be done after consulting the detailed information on the following topics in this IRP:
  - coiled tubing BOP stack and accumulator,
  - coiled tubing pipe specifications,
  - fluids and circulating systems,
  - well-pressure-containing equipment,
  - elastomeric seals, and
  - CT operations for well servicing and drilling.

1.8 **SPECIFYING OPERATIONAL PRACTICES AND PROCEDURES**

- The various recommended practices and best practices in this IRP shall be considered in the planning the operations and in designing the materials that will be used in the work applicable to the operation being conducted. This support should continue during the actual operations at the wellsite.
- CT operations practices and procedures appropriate for the tasks to be done should be specified.
- 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. If there is a risk of air being in the system, consult Section 18.4.3 of *IRP 18: Fire and Explosion Hazard Management* for guidance and a summary of critical risk factors. Procedures shall be in place to address any potentially hazardous situation identified.
Section 2 RECOMMENDED COILED TUBING BOP STACK AND ACCUMULATOR SPECIFICATIONS

This section addresses the following topics:

1. general recommended specifications regarding comparisons to jointed pipe operations, as well as strippers, BOP placement, primary flow point, check valves / tubing shutoff devices, reel isolation valves, pressure deployment, ram-type BOP elements, and underbalanced versus overbalanced operations;

2. BOP stack configuration recommendations for well servicing and drilling;

3. accumulator recommendations for well servicing and drilling accumulator systems.

For the definition of drilling operations consult the Glossary.

2.1 GENERAL RECOMMENDED SPECIFICATIONS

2.1.1 DEFINITIONS FOR THE PURPOSE OF THIS SECTION

In assessing the recommended well control configurations for servicing and drilling operations with coiled tubing, it is recognized that several configurations can be used to accomplish the same level of well control. It should also be recognized that different devices or components can be used to accomplish the same objectives. The following definitions may apply in this section:

- 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 bag, set of fixed diameter pipe rams, stripper element, or other technological advances that accomplish this objective.

- Variable pipe sealing element—a well control element that provides a pressure seal against sections of varying diameters. This may include an annular bag, a set of variable pipe rams, or other technological advances that accomplish this objective.

- Blanking element—a well control element that provides a pressure seal against an open wellbore. This would typically include a blind ram or other technological advances that accomplish the same objective.

- Shearing element—a well control element that provides a clean shear cut of the tubulars located across the element in the wellbore. This would typically include a shear ram or other technological advances that accomplish the same objective.
• 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. Inclusion of slip rams is a common practice, typically as a combination ram with a pipe ram function. Inclusion of slip rams into the recommended well control stacks of this IRP is not necessary to meet minimum requirements, but is recommended for underbalanced drilling and well servicing classes II, III, and IV. Where slip rams are run, it is further recommended that they be bi-directional in design.

Where any of these general terms above are used to describe components in a well control stack, the choice of the specific well control component is left the discretion of the operator.

Where specific components are referenced (e.g. annular bag, pipe ram, etc.), those components are recommended for operational or other functional reasons.

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 or bags, may be designed for pressure testing from below only.

2.1.2 **COILED TUBING VERSUS JOINTED PIPE OPERATIONS COMPARISONS**

In developing these recommendations, well control components for equivalent jointed pipe operations were reviewed with the intent of providing consistency and an equivalent level of well control between jointed pipe and CT operations. Where jointed pipe operations were generally considered to be overbalanced, the coiled tubing stripper was considered to be the equivalent of the hydrostatic head of the wellbore fluid.

In most situations the well control requirements for coiled tubing mirror those for jointed pipe operations, with the following exceptions:

1. Shear rams may be required where they are not required for equivalent jointed pipe operations. This recognizes that since coiled tubing is a continuous length of pipe without joints, it is not possible to back off a joint and drop the string, as would be the case for jointed pipe. Shear rams may be required for equivalent classes of wells from jointed pipe to enable a method of separation of the pipe.

2. Stabbing valves may be required for classes of jointed pipe operations but not for CT operations due to the absence of tool joints and the inability to install a stabbing valve into the string. Stabbing valves shall be used where BHAs cannot be lubricated above the wellhead valve of BOPs in one stage, and shall be lubricated in two or more stages out of the wellbore.

2.1.3 **STRIPPER CONSIDERATIONS**

Coiled tubing is well suited to underbalanced or “live-well” operations, and as such is normally used for servicing for those applications. In the well control configurations in this section (Section 2), it is acknowledged that not all CT
operations will be underbalanced and some may in fact be overbalanced.

For the configurations discussed in this section, the stripper in a live-well coiled tubing operation is the primary method of well control, and as such is considered the equivalent of the hydrostatic head of wellbore fluid in “dead-well” operations, which is also the primary method of well control. Accordingly, in the well control requirements described in this section, where the well is dead and full of kill fluid, the stripper shown is not required.

In underbalanced CT operations, the stripper would still be rigged up and a functional part of the well control system, but cannot be used to replace any other pipe-sealing element required in the stack. A non energized second stripper can be considered a well control device.

This is the case for servicing operations but may not be the case for grass-roots drilling operations where most if not all operations are dead-well.

2.1.4 BOP PLACEMENT CONSIDERATIONS

BOP placement should be directly above the wellhead assembly and below any lubricators or flow nipples.

This is done to avoid top-heavy BOP stacks and to allow manual control of the BOPs if necessary, without the need for a man-basket or other lifting device.

Placing the BOPs above the lubricator (servicing or underbalanced drilling) or guide tube / flow nipple (overbalanced drilling) can result in significant height to the BOP stack and complex BOP servicing or manual operation. It also provides for an additional connection, or potential leak point, below the BOP stack.

In some cases, a guide tube may be used to eliminate tubing buckling. There is no requirement for the guide tube to contain pressure.

2.1.5 PRIMARY FLOW POINT CONSIDERATIONS

The primary flow point can be above, below, or between the BOP elements. The decision as to where the primary flow point is located relative to the BOP elements shall consider the abrasive nature and chemical nature of the produced/circulated fluids, and it shall be determined that the well effluent will not be chemically or mechanically damaging to the BOP elastomers or ram/bag elements.

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

The issue of flowing above or below the BOPs has been a long-standing industry discussion. Flowing through the BOPs is common during drilling operations, but not during servicing operations. The distinction between drilling and servicing, and in some cases overbalanced and underbalanced operations, can be very fine from a practical point of view. Arguments related to flowing above or below the BOPs include the following:
• Well flow can be stopped or controlled in case of a washout of the flow tee or failure of the flowback system downstream of the BOP stack.

• The flow of sand or abrasives through the BOP stack can impair the ability of the well control components in the BOP stack to function on demand as required.

• Rig-up can be simplified by having testers rig onto the wing valve of the wellhead with BOPs rigged on top of the wellhead.

• Flowback of certain chemicals may have adverse effects, such as swelling of elastomers, on BOP components.

The recommended well control configurations described in this section take into account that there may be operational or other reasons that would suggest one configuration over another.

Refer to Section 6: Recommendations on Elastomeric Seals of this IRP for descriptions of elastomer compatibility issues.

2.1.6 CHECK VALVE / TUBING SHUTOFF DEVICE CONSIDERATIONS

► Check valves shall be used on all servicing operations unless the success or safety of the operation is jeopardized by the presence of check valves (examples would include where reverse circulation of the wellbore is required as a part of the programmed operation or running pressure activated firing heads). Check valves are required for underbalanced drilling, but not for overbalanced drilling operations. Additional contingences based on risk assessment shall be considered when check valve(s) are not used.

► For Class I servicing, where check valves cannot be run due to the nature of the servicing operation, shear rams are required in the well control stack as the alternative tubing shutoff mechanism.

► Underbalanced drilling operations require a dual check valve assembly.

Check valves prohibit flow up the coiled tubing from the bottom of the string, and protect against wellbore flow in the event of a tubing failure. Operations such as coil fracturing may require reverse circulation through the coiled tubing, in which case a check valve is not required. With the exception of such cases, Class I well servicing operations require only a single check valve assembly. Class II, Class III, and critical well servicing operations require dual check valve assemblies.

Overbalanced drilling operations do not require check valve assemblies as the operation is a dead-well operation and kill fluid is ready to pump down the annulus in the event of a reel valve or surface coil failure.

2.1.7 REEL ISOLATION VALVE CONSIDERATIONS

► For servicing and drilling operations where the well is or is expected to be live, an isolation valve shall be located at the reel and downstream from the rotating joint.
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 CT string.

The reel iron, swivel and reel isolation valve require an iron management system in place, which should include, but not limited to, pressure testing to maximum anticipated working pressure, and material thickness testing.

An isolation valve is required to prevent the possibility of uncontrolled flow at surface in the event of a rotating joint leak. This valve is required to isolate the rotating joint from the wellbore in the event repair of the rotating joint is to be done.

2.1.8 PRESSURE DEPLOYMENT CONSIDERATIONS

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 a method of holding the BHA in the BOP stack and further provides a method of containing wellbore pressure during the deployment procedure. This can be in the form of an enclosed hands-free deployment system, or alternatively by the addition of an annular bag or set of pipe rams sized for the BHA, which is in addition to the well control components normally required.

In some cases, a BHA is run that is of such a length that it cannot be swallowed inside the lubricator and above the blinds or master valve. Then, the BHA may need to be removed in two or more sections. When this is the case, an additional set of sealing rams or annular bag is required to provide isolation from the wellbore during removal of the upper section of the BHA.

2.1.9 RAM-TYPE BOP ELEMENT CONSIDERATIONS

All ram-type BOP elements must be hydraulically operated, with a backup system as specified in Section 2.3: Accumulator Recommendations, and have the ability to be locked in service.

When run in the BOP stack whether required or not, shear rams shall be capable of cutting the outer CT string and any inner strings such as a CT string, wireline, capillary, or combination of these strings.

When slip rams are run in the BOP stack, the hydraulic fluid requirements for the slip rams shall be included in the total fluid requirements for the BOP stack.

2.1.10 UNDERBALANCED VERSUS OVERBALANCED OPERATION CONSIDERATIONS

Coiled tubing is well suited to underbalanced or "live-well" operations for servicing. However, grass-roots drilling is typically conducted in an overbalanced condition. For overbalanced drilling operations, the hydrostatic head of the drilling fluid controls well pressure under normal operating conditions such that a coiled tubing stripper is not required.
A stripper is required when conducting underbalanced operations.

For overbalanced drilling operations, a stripper may be included in the well control stack but would be considered as redundant equipment and shall not be considered to be an alternative for any one of the recommended pipe-sealing elements.

## 2.2 BOP Stack Configuration Recommendations

Note: Throughout this document, samples of recommended BOP configurations are shown. Best efforts have been made to represent configurations that are typical in the operating industry. However, these configurations should not be considered exclusive of alternate configurations that provide equivalent or additional levels of well control, whether that be through combination ram functions or alternate pipe-sealing methods.

### 2.2.1 Well Servicing Configurations

Notes:

1. For figures 1 to 7, threaded connections are suitable for threaded wellheads. Where regulation requires that the wellhead be flanged, connections up to the uppermost BOP element must be flanged.

2. Wellhead valves / configurations are shown for illustrative purposes only and are not meant to reflect the regulatory requirements.

**WELL SERVICING CLASS I – CLASS I WELLS MEET THE FOLLOWING CONDITIONS:**

(a) reservoir pressure < 5,500 kPa (798 psi),
(b) no H₂S in a representative sample of the gas, and
(c) produced fluid is either of the following:
   - gas,
   - heavy oil producer with oil density > 920 kg/m³, gas-oil ratio < 70 sm³/m³, and produces by primary recovery or is part of a waterflood.

**CLASS I SERVICING**

- Subject to Section 2.1.6: Check Valve / Tubing Shutoff Device Considerations, a single check valve or float assembly is required on Class I servicing operations.

- Well control systems for Class I servicing operations using coiled tubing shall contain a minimum of one pipe sealing element in addition to the coiled tubing stripper.

- Two flare lines – minimum diameter 50.8mm extending from well, or
One flare line – minimum diameter 75mm extending from well

See Figure 1 below for the recommended configuration for Class I servicing operations.

**Figure 1: Diagram of Recommended Configuration for Class I Servicing Operations**
WELL SERVICING CLASS II - CLASS II WELLS MEET EITHER OF THE FOLLOWING CONDITIONS:

(a) pressure rating of the production casing flange ≤ 21,000 kPa (3,046 psi), or
(b) \( \text{H}_2\text{S} \) content < 1% by volume.

CLASS II SERVICING

- Subject to Section 2.1.6: Check Valve / Tubing Shutoff Device Considerations, a dual check valve or float assembly is required on Class II servicing operations.

- Well control systems for Class II servicing operations using coiled tubing shall contain a minimum of one blanking element, one shearing element, and one pipe sealing element in addition to the coiled tubing stripper. In most cases, this configuration would be provided with a quad BOP stack. This can be replaced with a combination stack (i.e. “combi”) with blind / shear rams and pipe/slip rams.

- 50mm lines throughout.

- See below for the recommended configuration for Class II servicing operations for quad stack (Figure 2) and combination stack (Figure 3).

CLASS IIA SERVICING

- If rigging up on a side entry sub it is acceptable to utilize an annular bag and a stripper in order to minimize the bending moment. In situations where a side entry sub is not used a Class II well control stack shall be used.
Figure 2: Diagram of Recommended Configuration for Class II Servicing Operations – Quad Stack

Stripper

Quad rams

Blind rams
Shear rams
Slip rams
Pipe rams

Flow tee

Crossover

Wellhead master valve

ACCUMULATOR SYSTEM
Figure 3: Diagram of Recommended Configuration for Class II Servicing Operations – Combination Stack
Well Servicing Class III – Class III wells meet either of the following conditions:
(a) pressure rating of the production casing flange > 21,000 kPa (3,046 psi),
(b) pressure rating of the production casing flange ≤ 21,000 kPa (3,046 psi), and
(c) H₂S content ≥ 1% by volume.

CLASS III SERVICING - CLASS III WELLS MEET EITHER OF THE FOLLOWING CONDITIONS:

► Well control systems for Class III servicing operations using coiled tubing shall contain a minimum of a blanking element, a shearing element, and two pipe sealing elements in addition to the coiled tubing stripper. The figure below shows a configuration with a quad BOP stack. This can be replaced with a combination stack.

► A dual check valve or float assembly is required on Class III servicing operations.

► 50mm lines throughout.

▷ See below for the recommended configuration for Class III servicing operations for quad BOP (Figure 4) and combination BOP (Figure 5).
**Figure 4: Diagram of Recommended Configuration for Class III Servicing Operations – Quad BOP**

*Note: The annular bag could be replaced with a set of pipe rams above or below the quad BOPS, or a non energized stripper.*
Figure 5: Diagram of Recommended Configuration for Class III Servicing Operations – Combination BOP

*Note: The annular bag could be replaced with a set of pipe rams above or below the quad BOPS, or a non energized stripper.
CRITICAL SOUR SERVICING

- Well control systems for critical sour servicing operations using coiled tubing shall contain a minimum of a blanking element, a shearing element, and three pipe sealing elements, in addition to the coiled tubing stripper. The figure below shows a configuration with a quad BOP stack. This can be replaced with a combination stack.

- A dual check valve or float assembly is required on critical sour servicing operations.

- See Figure 6 below for the recommended configuration for critical sour servicing operations – quad BOP.

- See Figure 7 below for the recommended configuration for critical sour servicing operations – combination BOP.

Figure 6: Diagram of Recommended Configuration for Critical Sour Servicing Operations – Quad BOP

*Note: The annular bag could be replaced with a set of pipe rams above or below the quad BOPS, or a non-energized stripper.

The pipe rams described below the quad BOP would be most common; however, this could be replaced by an annular bag.

For hole volume requirements, see Section 4.2.3: Completion Fluid Volume and Storage.

For kill pump requirements, see Section 4.2.1: Surface Equipment / Back-up Pumps.
*Note: The annular bag could be replaced with a set of pipe rams above or below the quad BOPS, or a non energized stripper.

The pipe rams described below the combi BOP would be most common; however, this could be replaced by an annular bag.

For hole volume requirements, see Section 4.2.3: Completion Fluid Volume and Storage.

For kill pump requirements, see Section 4.2.1: Surface Equipment / Back-up Pumps.
2.2.2 **DRILLING CONFIGURATIONS**

Note: Wellhead valves / configurations are shown for illustrative purposes only and are not meant to reflect the regulatory requirements.

For wells drilled in British Columbia consult Oil and Gas Commissions Directives / Regulations on well control requirements.

**CLASS I DRILLING – OVERBALANCED**

- Well control systems for Class I drilling operations using coiled tubing shall contain a minimum of one pipe sealing element.
- Class I drilling systems must have a minimum pressure rating of 1,400 kPa.
- Consult jurisdictional requirements for depth and other limitations for this class of well.

Note that unlike some configurations, replacing the annular bag with pipe rams is not acceptable as a pipe-sealing element in Class I drilling applications due to the presence of drill collars and positive displacement motors that may place components of variable diameter across the pipe rams and inhibit the sealing capabilities.

A check valve or float assembly is not required.

- See Figure 8 below for the recommended configuration of drilling blowout prevention systems for Class I drilling operations.
**Figure 8: Diagram of Recommended Configuration of Overbalanced Drilling Blowout Prevention System for Drilling Operations – Class I**

*Note:*

1. The diverter line must be a minimum nominal diameter of 152 mm throughout.

2. Connections between the top of annular preventer and injector head do not have to be flanged or meet the minimum pressure rating requirements. The stripper is optional.
CLASS II DRILLING – OVERBALANCED

- Well control systems for Class II drilling operations using coiled tubing shall contain a minimum of one variable pipe-sealing element, one blanking element, a kill spool, and one pipe-sealing element. Threaded connections in the manifold system are acceptable.

- Class II drilling systems must have a minimum pressure rating of 7,000 kPa.

- Consult jurisdictional requirements for depth and other limitations for this class of well.

A check valve or float assembly is not required.

- See Figure 9 below for the recommended configuration of drilling blowout prevention systems for Class II drilling operations.

Figure 9: Diagram of Recommended Configuration of Overbalanced Drilling Blowout Prevention System for Drilling Operations – Class II
Note:

1. Bleed-off line, centre line through choke manifold, and flare line must be a minimum nominal diameter of 76.2 mm throughout.

2. Lines through chokes must be a minimum nominal diameter of 50.8 mm throughout.

3. Kill line must be a minimum nominal diameter of 50.8 mm throughout.

4. Flanged pipe connections must be used from the drilling spool down to and including the connection to the choke manifold. The remainder of the choke manifold may contain threaded fittings.

5. Connections between the top of the annular preventer and injector head do not have to be flanged or meet the minimum pressure rating requirements. The stripper is optional.

6. Minimum pressure rating for flare and degasser inlet lines is 7 MPa.

7. Hydraulic and manual valve positions in bleed-off line may be interchangeable.

8. An optional BOP stack arrangement (for Class II wells only) would allow the pipe ram to be placed above the drilling spool.

9. Ram-type BOPs manufactured with integral outlets may be used in place of the drilling spool.

**CLASS III DRILLING – OVERBALANCED**

- Well control systems for Class III drilling operations using coiled tubing are equivalent to Class II operations but require a minimum pressure rating of 14000 kPa. Threaded connections in the manifold system are acceptable.

- Class III systems shall contain a minimum of one variable pipe-sealing element, one blanking element, a kill spool, and one pipe-sealing element.

- Consult jurisdictional requirements for depth and other limitations for this class of well.

A check valve or float assembly is not required.

- See Figure 10 below for the recommended configuration of drilling blowout prevention systems for Class III drilling operations.
Figure 10: Diagram of Recommended Configuration of Overbalanced Drilling Blowout Prevention System for Drilling Operations – Class III
Note:

1. Bleed-off line, centre line through choke manifold, and flare line must be a minimum nominal diameter of 76.2 mm throughout.

2. Lines through chokes must be a minimum nominal diameter of 50.8 mm throughout.

3. Kill line must be a minimum nominal diameter of 50.8 mm throughout.

4. Flanged pipe connections must be used from the drilling spool down to and including the connection to the choke manifold. The remainder of the choke manifold may contain threaded fittings.

5. Connections between the top of the annular preventer and injector head do not have to be flanged or meet the minimum pressure rating requirements. The stripper is optional.

6. Minimum pressure rating for flare and degasser inlet lines is 14 MPa.

7. Hydraulic and manual valve positions in bleed-off line may be interchangeable.

8. Ram-type BOPs manufactured with integral outlets may be used in place of the drilling spool.

CLASS IV DRILLING – OVERBALANCED

Well control systems for Class IV drilling operations using coiled tubing are equivalent to Class II and Class III operations but require a minimum pressure rating of 21000 kPa and require flanged connections throughout the manifold system.

Well control systems for Class IV drilling operations using coiled tubing shall contain a minimum of one variable pipe-sealing element, one blanking element, a kill spool, and one pipe-sealing element.

Consult jurisdictional requirements for depth and other limitations for this class of well.

A check valve or float assembly is not required.

See Figure 11 below for the recommended configuration of drilling blowout prevention systems for Class IV drilling operations.
Figure 11: Diagram of Recommended Configuration of Overbalanced Drilling Blowout Prevention System for Drilling Operations – Class IV

VENT (outside building)

ACCUMULATOR SYSTEM

Inlet line to mud-gas separator

Flanged connections throughout

CHOKE MANIFOLD

50.8 mm

To flare pit/tank

BLOWOUT PREVENTION STACK

50.8 mm

50.8 mm throughout

76.2 mm throughout

76.2 mm

50.8 mm
Note:

1. Bleed-off line, centre line through choke manifold, and flare line must be a minimum nominal diameter of 76.2 mm throughout.

2. Lines through chokes must be a minimum nominal diameter of 50.8 mm throughout.

3. Kill line must be a minimum nominal diameter of 50.8 mm throughout.

4. Flanged pipe connections must be used from the drilling spool to the last valve on the choke manifold inclusive.

5. Connections between the top of the annular preventer and injector head do not have to be flanged or meet the minimum pressure rating requirements. The stripper is optional.

6. Minimum pressure rating for flare and degasser inlet lines is 14 MPa.

7. Hydraulic and manual valve positions in bleed-off line may be interchangeable.

8. Ram-type BOPs manufactured with integral outlets may be used in place of the drilling spool.

**CLASS V DRILLING – OVERBALANCED**

► Well control systems for Class V drilling operations using coiled tubing require a minimum pressure rating of 34000 kPa and require flanged connections throughout the manifold system.

► Well control systems for Class V drilling operations using coiled tubing shall contain a minimum of one variable pipe-sealing element, two pipe-sealing elements, one blanking element, one shearing element, and two kill/bleed-off spools.

► Shear rams and blind rams are considered required due to the higher potential for pressure due to the depths involved. These ram functions can be separate elements or combined into a common blind / shear element. This increase in ram functions recognizes the additional requirement for a lower Kelly-cock valve for Class V drilling with jointed pipe.

Consult jurisdictional requirements for depth and other limitations for this class of well

► A check valve or float assembly may be required.

► See Figure 12 below for the recommended configuration of drilling blowout prevention systems for Class V drilling operations.
Figure 12: Diagram of Recommended Configuration of Overbalanced Drilling Blowout Prevention System for Drilling Operations – Class V (Minimum Pressure Rating 34,000 kPa)

BLOWOUT PREVENTION STACK

ACCUMULATOR SYSTEM

CHOKE MANIFOLD
Note:

1. Kill lines, bleed-off lines, choke manifold, and flare lines must be minimum nominal diameter of 76.2 mm throughout.

2. Flanged pipe connections must be used from the drilling spool to the last valve on the choke manifold inclusive.

3. Connections between the top of the annular preventer and injector head do not have to be flanged or meet the minimum pressure rating requirements. The stripper is optional.

4. Minimum pressure rating for flare and degasser inlet lines is 14 MPa.

5. Hydraulic and manual valve positions in the bleed-off line may be interchangeable.

6. For optional BOP stack configurations, see the BOP stack configurations for critical sour wells.

7. Ram-type BOPs manufactured with integral outlets may be used in place of the drilling spool.

CLASS VI DRILLING – OVERBALANCED

Well control systems for Class VI drilling operations using coiled tubing are equivalent to Class V systems with the exception of requiring a minimum pressure rating of 69000 kPa and require flanged connections throughout the manifold system.

Well control systems for Class VI drilling operations using coiled tubing must contain a minimum of one variable pipe-sealing element, two pipe-sealing elements, one blanking element, one shearing element, and two kill / bleed-off spools.

Shear rams and blind rams are considered required due to the higher potential for pressure due to the depths involved. These ram functions can be separate elements or combined into a common blind / shear element. This increase in ram functions recognizes the additional requirement for a lower Kelly-cock valve for Class VI drilling with jointed pipe.

A check valve or float assembly is required.

Consult jurisdictional requirements for depth and other limitations for this class of well.

See Figure 13 below for the recommended configuration of drilling blowout prevention systems for Class VI drilling operations.
Figure 13: Diagram of Recommended Configuration of Overbalanced Drilling Blowout Prevention System for Drilling Operations – Class VI (Minimum Pressure Rating 69,000 kPa)
Recommended Coiled Tubing BOP Stack and Accumulator Specifications

Note:

1. Kill lines, bleed-off lines, choke manifold, and flare lines must be minimum nominal diameter of 76.2 mm throughout.

2. Flanged pipe connections must be used from the drilling spool to the last valve on the choke manifold inclusive.

3. Connections between the top of the annular preventer and injector head do not have to be flanged or meet the minimum pressure rating requirements. The stripper is optional.

4. Minimum pressure rating for flare and degasser inlet lines is 14 MPa.

5. Hydraulic and manual valve positions in the bleed-off line may be interchangeable.

6. For optional BOP stack configurations, see the BOP stack configurations for critical sour wells.

7. Ram-type BOPs manufactured with integral outlets may be used in place of the drilling spool.

CRITICAL SOUR DRILLING – OVERBALANCED

➢ Well control systems for critical sour drilling operations using coiled tubing shall contain a minimum of a primary flow port, an annular bag (variable pipe-sealing element), two pipe-sealing elements, a blanking element, a shearing element, and two kill / bleed-off spools.

➢ A dual check valve or float assembly is required for critical sour drilling.

▷ Three options of common recommended configurations are illustrated in figures 14 to 16.

➢ Kill lines, bleed-off lines, choke manifold, and flare line sizes shall be minimum nominal diameters as described for the depth of well as shown in figures 8 to 13.

Note: In some cases, the option 1 configuration could be provided with a quad BOP stack. This can be replaced with a combination stack (i.e. combi) to replace the pipe rams and blind / shear rams.
Figure 14: Diagram of Recommended Configuration of Drilling Blowout Prevention System for Overbalanced Drilling Operations – Critical Sour – Option 1

Notes:

1. Bleed-off, kill line, and manifold line sizes are to be determined by the well depth as described in figures 8 to 13.

2. Required pressure rating to be determined by the well depth as described in Figures 9 through 13.
Figure 15: Diagram of Recommended Configuration of Drilling Blowout Prevention System for Overbalanced Drilling Operations – Critical Sour – Option 2

Notes:

1. Bleed-off, kill line, and manifold line sizes are to be determined by the well depth as described in figures 8 to 13.

2. Required pressure rating to be determined by the well depth as described in Figures 9 through 13.

Symbols:

- Manually operated valve
- Check valve
- HCR valve (either inside or outside of manual valve)
Figure 16: Diagram of Recommended Configuration of Drilling Blowout Prevention System for Overbalanced Drilling Operations – Critical Sour – Option 3

Notes:

1. Bleed-off, kill line, and manifold line sizes are to be determined by the well depth as described in figures 8 to 13.

2. Required pressure rating to be determined by the well depth as described in Figures 9 through 13.
UNDERBALANCED DRILLING

- The stripper in a live-well coiled tubing operation is the primary method of well control, and as such is considered the equivalent of the hydrostatic head of wellbore fluid in “dead-well” operations, which is also the primary method of well control in that operation. Accordingly, for underbalanced drilling operations for classes I to VI, the required minimum well control configuration shall be as shown in figures 8 to 13, with the addition of a coiled tubing stripper.

- If the BHA cannot be fully deployed into the lubricator above the blind rams or wellhead valve, an annular bag shall be added above the blind rams and slip rams sized for the BHA, or an equivalent means of holding the BHA in place during pressure deployment shall be added to the stack.

- A dual check valve or float assembly is required for underbalanced drilling.

- As discussed in Section 2.1.1: Definitions for the Purpose of this Section, inclusion of slip rams into the recommended well control stacks of this IRP is not necessary to meet minimum requirements, but is recommended. Where slip rams are run, it is further recommended that they be bi-directional in design.

CRITICAL SOUR UNDERBALANCED DRILLING

- The stripper in a live-well coiled tubing operation is the primary method of well control, and as such is considered the equivalent of the hydrostatic head of wellbore fluid in “dead-well” operations, which is also the primary method of well control in that operation. Accordingly, for critical underbalanced drilling operations the required minimum well control configuration shall be as shown in figures 14 to 16, with the addition of a coiled tubing stripper.

- A dual check valve or float assembly is required for critical sour underbalanced drilling.

- As discussed in Section 2.1.1, inclusion of slip rams into the recommended well control stacks of this IRP is not necessary to meet minimum requirements, but is recommended. Where slip rams are run, it is further recommended that they be bi-directional in design.

- Well control systems for critical sour underbalanced drilling operations using coiled tubing shall contain a minimum of one coiled tubing stripper, a lubricator with primary flowline, a variable pipe-sealing element, two pipe-sealing elements, a shearing element, a blanking element, and two kill/bleed-off spools.

If BOP Option 2 or BOP Option 3 is used, an appropriately sized ram blanking tool that fits into the top pipe ram must be on location and readily available. This allows the top pipe ram to perform the function of a blind ram when the
drill string is out of the hole. In addition, if BOP Configuration 3 is used, there
must be sufficient surface or intermediate casing to contain the maximum
anticipated.

Figure 17: Diagram of Recommended Configuration of Drilling Blowout Prevention System
for Drilling Operations – Critical Sour Underbalanced Drilling – Option 1

Notes:
1. Bleed-off, kill line, and manifold line sizes are to be determined by the well depth as
described in figures 8 to 13.

2. Required pressure rating to be determined by the well depth as described in Figures 9
through 13.
Figure 18: Diagram of Recommended Configuration of Drilling Blowout Prevention System for Drilling Operations – Critical Sour Underbalanced Drilling - Option 2

Notes:

1. **Bleed-off, kill line, and manifold line sizes are to be determined by the well depth as described in figures 8 to 13.**

2. **Required pressure rating to be determined by the well depth as described in Figures 9 through 13.**
Figure 19: Diagram of Recommended Configuration of Drilling Blowout Prevention System for Drilling Operations – Critical Sour Underbalanced Drilling - Option 3

Notes:

1. Bleed-off, kill line, and manifold line sizes are to be determined by the well depth as described in figures 8 to 13.

2. Required pressure rating to be determined by the well depth as described in Figures 9 through 13.
2.3 ACCUMULATOR RECOMMENDATIONS

2.3.1 WELL SERVICING ACCUMULATOR SYSTEMS

ACCUMULATOR SYSTEMS

- All BOPs must be hydraulically operated and connected to an accumulator system. It must be capable of providing, without recharging, hydraulic fluid of sufficient volume and pressure to close all active BOP components in their required function, concurrently, and retain a minimum pressure of 8,400 kPa on the accumulator system.

- The accumulator system must be capable of functioning all required and active BOP components in the stack. An “active” BOP component is any BOP component that is not locked out, regardless of whether or not it is required in the stack to meet minimum requirements. 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.

- If additional BOP equipment has been installed and is in use, there must be sufficient usable hydraulic fluid available to close the additional BOP components and meet the requirements above. All additional BOP equipment that is not in service must be locked out (e.g. unplugged, handles removed, lines disconnected, etc.).

- If the existing accumulator system cannot meet these requirements because of the addition of the shear ram or blind / shear rams, the accumulator system’s capacity and / or pressure must be increased or a separate accumulator system must be installed. It is also acceptable to supplement the existing accumulator system with a N₂ booster that will provide sufficient volume and pressure to shear the tubulars, and retain a minimum accumulator pressure of 8,400 kPa or the minimum pressure required to shear the tubulars, whichever is greater.

- The accumulator system must be installed and operated according to manufacturer’s specifications. All accumulator specifications must be available at the coil unit (i.e. manufacturer, number of bottles, capacity of bottles, design pressure, etc.).

- The accumulator system must be connected to the BOPs with hydraulic lines (steel and/or non-steel) of working pressure equal to or greater than the working pressure of the accumulator.

- All non-steel hydraulic BOP lines located within 7 m 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 5 minutes of 700° C flame temperature at maximum working pressure without failure.

- The accumulator system must be recharged by an automatic pressure-
controlled pump capable of recovering within 5 minutes the accumulator pressure drop resulting from the function test of the required BOP components.

When the accumulator is recharged by the unit’s hydraulic system (for well classes I, II, and IIA), it is acceptable to increase the RPM of the unit’s engine to meet the 5 minute recharge requirement.

- For all well classes, 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.

- For all classes, the accumulator system must be as follows:
  - 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 precharge pressure of the accumulator bottles,
  - readily accessible, and
  - connected to a back-up nitrogen system.

- For Class I, II, and IIA wells, the accumulator must be located a minimum of 7 m from the wellbore.

- For Class III and critical sour wells, the accumulator must be as follows:
  - independent (i.e. separate hydraulic pump and hydraulic reservoir) of the unit hydraulics and located a minimum of 15 m (or as per jurisdictional requirements) from the wellbore,
  - shielded or housed to ensure that the system can be protected from the well in the event of an uncontrolled flow, and
  - vented on the accumulator reservoir so that venting takes place outside of a confined space.

**BACK-UP NITROGEN (N₂) SYSTEMS**

- The accumulator system must be connected to a back-up N₂ system.

- The back-up N₂ system must be capable of providing N₂ of sufficient volume and pressure to close all active BOP components in their required function concurrently, and retain a minimum pressure of 8,400 kPa on the back-up N₂ system.

- The back-up N₂ system must be capable of functioning all required and active BOP components in the stack. 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.
If additional BOP equipment has been installed and is in use, there must be sufficient usable hydraulic fluid available to close the additional BOP components and meet the requirements above. All additional BOP equipment that is not in service must be locked out (e.g. unplugged, handles removed, lines disconnected, etc.).

The backup N₂ system must be connected such that it will function the BOPs as described above, and not allow the N₂ to discharge into the accumulator reservoir or the accumulator bottles.

When the back-up N₂ system is tied in downstream of an accumulator regulator valve or valves, isolation valves are required to prevent venting of N₂ through the regulator into the accumulator reservoir tank.

The back-up N₂ system must be readily accessible and be equipped with a gauge or have a gauge readily available for installation to determine the back-up N₂ pressure.

For Class I, II, and IIA wells, the back-up N₂ system must be located a minimum of 7 m from the wellbore.

For Class III and critical sour wells, the back-up N₂ system must be located a minimum of 15 m from the wellbore and housed to ensure the system can be protected from the well in the event of an uncontrolled flow.

**BOP OPERATING CONTROLS**

The accumulator system must include operating controls at the normal operating position (control cab for deep units, back of truck for intermediate/shallow units) and remote positions for each BOP.

The position of the operating handles (open/neutral/closed) of the BOP operating controls at the operator’s or remote position shall not prevent the operation of the BOP components from the other position (operator’s or remote). That is, regardless of the position of the operating handles in the CT unit, the crew shall be able to close the BOPs from the remote position so that in the event of an emergency it would not be necessary to return to the CT unit to reposition the operating handles of the BOP controls.

**BOP CT UNIT OPERATING CONTROLS**

The BOP CT unit operating controls must meet the following requirements:

- Each BOP component must have a separate operating control located near the operator’s position.
- They must be capable of opening and closing each BOP component.
- Each BOP CT unit control must be properly installed, readily accessible, correctly identified, and show function operations (i.e. open and close).
- They must be equipped with a gauge indicating the accumulator system pressure.
BOP REMOTE OPERATING CONTROLS

- The BOP remote operating controls must meet the following requirements:
  - Each BOP component must have a separate operating control located at the remote position.
  - They shall be capable of closing each BOP component—for critical sour wells, the remote controls shall be capable of opening and closing each BOP component.
  - Each BOP remote control must be properly installed, correctly identified, and show function operations (e.g. open and close).
  - The BOP remote controls must be readily accessible and be equipped with a gauge to determine accumulator system pressure.
  - For Class I, II, and IIA wells, the controls must be located at a remote position a minimum of 7 m from the well.
  - For Class III and critical sour wells, the 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.

2.3.2 DRILLING ACCUMULATOR SYSTEMS

ACCUMULATOR SYSTEMS

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

- The accumulator system must meet the following requirements:
  1. For Class I wells, it must be capable of providing without recharging, hydraulic fluid of sufficient volume and pressure to do the following:
     - open the hydraulically operated valve (HCR) on the diverter line,
     - close the annular preventer on drill pipe / coiled tubing, and
     - retain a minimum pressure of 8,400 kPa on the accumulator system.
  2. For Class II, III, and IV wells, it must be capable of providing without recharging, hydraulic fluid of sufficient volume and pressure to do the following:
     - open the HCR on the bleed-off line,
     - close the annular preventer on drill pipe / coiled tubing,
     - close one ram preventer, and
     - retain a minimum pressure of 8,400 kPa on the accumulator system.
  3. For Class V and VI wells, it must be capable of providing without recharging, hydraulic fluid of sufficient volume and pressure to do the
Recommended Coiled Tubing BOP Stack and Accumulator Specifications

following:
- open the HCR on the bleed-off line,
- close the annular preventer on the drill pipe / coiled tubing,
- close two ram preventers, and
- retain a minimum pressure of 8,400 kPa on the accumulator system.

In addition to the above functions, the accumulator system for CTUs drilling classes V and VI wells must also provide sufficient volume and pressure to shear the coiled tubing and retain on the accumulator system a minimum pressure of 8,400 kPa or the minimum pressure required to shear the coiled tubing, whichever is greater.

If the existing accumulator system cannot meet these requirements because of the closing volume requirements for the shear ram, the accumulator system’s capacity and/or pressure must be increased or a separate accumulator system must be installed. It is also acceptable to supplement the existing accumulator system with a nitrogen (N₂) booster that will provide sufficient volume and pressure to shear the coiled tubing and retain a minimum accumulator pressure of 8,400 kPa or the minimum pressure required to shear the coiled tubing, whichever is greater.

For critical sour wells, it shall be capable of providing without recharging, hydraulic fluid of sufficient volume and pressure to do the following:
- open the HCR on the bleed-off line,
- close the annular preventer on the drill pipe / coiled tubing,
- close, open, and close one ram preventer, and
- if blind / shear rams are installed, provide sufficient volume and pressure to shear the drill pipe / coiled tubing, and retain on the accumulator system a minimum pressure of 8,400 kPa or the minimum pressure required to shear the drill pipe / coiled tubing, whichever is greater.

If the existing accumulator system cannot meet these requirements because of the addition of the blind / shear rams, the accumulator system’s capacity and/or pressure must be increased or a separate accumulator system must be installed. It is also acceptable to supplement the existing accumulator system with a nitrogen (N₂) booster that will provide sufficient volume and pressure to shear the drill pipe / coiled tubing and retain a minimum accumulator pressure of 8,400 kPa or the minimum pressure required to shear the drill pipe / coiled tubing, whichever is greater.

The accumulator system must be installed and operated according to the accumulator manufacturer’s specifications. All accumulator specifications must be available at the rig/unit (e.g. manufacturer, number of bottles, capacity of bottles, design pressure, etc.).

The accumulator system must be connected to the BOPs and the HCR on the bleed-off line, with hydraulic BOP lines (steel and/or non-steel) of working
pressure equal to or greater than the manufacturer’s design pressure of the accumulator.

- All non-steel hydraulic BOP lines located within 7 m 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 5 minutes of 700°C flame temperature at maximum working pressure without failure.

- All hydraulic BOP line end fittings located within 7 m of the wellbore shall be fire rated to withstand a minimum of 5 minutes of 700°C flame temperature at maximum working pressure without failure.

- For Class I to IV wells, the accumulator system must be equipped with an automatic pressure-controlled recharge pump capable of recovering within 5 minutes the accumulator pressure drop resulting from the function tests of the BOP components (for the required well class as noted above) and the HCR on the diverter / bleed-off line.

- For Class V and VI wells and critical sour wells, the accumulator system must be equipped with two separate automatic pressure-controlled recharge pumps. The primary pump must be capable of recovering within 5 minutes the accumulator pressure drop resulting from the function test of the BOP components and the HCR on the bleed-off line. The secondary pump must be capable of recovering within 5 minutes the accumulator pressure drop resulting from opening the HCR and closing the annular preventer on drill pipe.

- A check valve must be installed in the accumulator hydraulic system for all well classes. The check valve must be located between the accumulator charge pumps and the accumulator bottles.

- The accumulator system must be capable of closing any ram-type BOP within 30 seconds.

- It must be capable of closing any annular-type BOP of a size up to and including 350 mm bore diameter within 60 seconds.

- It must be capable of closing any annular type BOP of a size greater than 350 mm bore diameter within 90 seconds.

- It must be equipped with an accurate gauge to determine accumulator system pressure.

- It must be equipped with readily accessible fittings and gauge to determine the precharge pressure of the accumulator bottles.

- It must be readily accessible.

- It must be housed to ensure the system can be protected from the well in the event of an uncontrolled flow.

- It must be adequately heated to maintain the accumulator’s effectiveness.
It shall be located at least 15 m (must meet jurisdictional requirements) from the wellbore.

The vent on the accumulator reservoir shall be installed such that venting takes place outside the building (side or top of building).

The accumulator system must be connected to a back-up nitrogen system.

ADDITIONAL BOP EQUIPMENT

If additional BOP equipment has been installed and is in use, there must be sufficient usable hydraulic fluid available to close the additional BOP components and meet the requirements of the preceding “Accumulator Systems” section.

All additional BOP equipment that is not in service must be locked out, have the control handles removed, or have the lines disconnected.

BACK-UP NITROGEN (N₂) SYSTEMS

For Class I wells, the back-up N₂ system must be capable of providing N₂ of sufficient volume and pressure to do the following:

- open the HCR on the diverter line,
- close the annular preventer on the drill pipe / coiled tubing, and
- retain a minimum pressure of 8,400 kPa on the backup N₂ system.

For Class II, III, and IV wells, the back-up N₂ system must be capable of providing N₂ of sufficient volume and pressure to do the following:

- open the HCR on the bleed-off line,
- close the annular preventer on the drill pipe / coiled tubing,
- close one ram preventer, and
- retain a minimum pressure of 8,400 kPa on the back-up N₂ system (see Section 6.2.1 of Alberta ERCB Directive 036: Drilling Blowout Prevention Requirements and Procedures if additional BOP equipment has been installed and is in use).

For Class V and VI wells, the back-up N₂ system must be capable of providing N₂ of sufficient volume and pressure to do the following:

- open the HCR on the bleed-off line,
- close the annular preventer on the drill pipe / coiled tubing,
- close two ram preventers, and
- retain a minimum pressure of 8,400 kPa on the back-up N₂ system.

In addition to the above functions, the back-up N₂ system for CTUs drilling Class V and VI wells must also provide sufficient volume and pressure to shear the coiled tubing and retain on the backup N₂ system a minimum
pressure of 8,400 kPa or the minimum pressure required to shear the coiled tubing, whichever is greater.

- If the existing back-up N₂ system cannot meet these requirements because of the closing volume requirements of the blind shear ram, the back-up N₂ system’s capacity and/or pressure must be increased or a separate back-up N₂ system must be installed. It is also acceptable to supplement the existing back-up N₂ system with an N₂ booster (this may be the same N₂ booster system that supplements the accumulator).

- For critical sour wells, the back-up N₂ system must be capable of providing N₂ of sufficient volume and pressure to do the following:
  - open the HCR on the bleed-off line,
  - close the annular preventer on the drill pipe / coiled tubing,
  - close, open, and close one ram preventer, and
  - if blind / shear rams are installed, provide sufficient volume and pressure to shear the drill pipe / coiled tubing, and retain on the back-up N₂ system a minimum pressure of 8,400 kPa or the minimum pressure required to shear the drill pipe / coiled tubing, whichever is greater.

- For critical sour wells, if the existing back-up N₂ system cannot meet these requirements because of the addition of the blind / shear rams, the back-up N₂ system’s capacity and/or pressure must be increased or a separate back-up N₂ system must be installed. It is also acceptable to supplement the existing back-up N₂ system with an N₂ booster (this may be the same N₂ booster system that supplements the accumulator).

- The back-up N₂ system must be connected so that it will operate the BOPs and HCR on the bleed-off line, as described above, and not allow the N₂ to discharge into the accumulator reservoir or the accumulator bottles (see Appendix 3 of Alberta ERCB Directive 036: Drilling Blowout Prevention Requirements and Procedures).

- When the back-up N₂ system is tied in downstream of an accumulator regulator valve or valves, isolation valves are required to prevent venting of N₂ through the regulator into the accumulator reservoir tank.

- In addition, the backup N₂ system must be as follows:
  - equipped with a gauge or have a gauge readily available for installation to determine the back-up N₂ pressure,
  - readily accessible,
  - housed to ensure that the system can be protected from the well in the event of an uncontrolled flow,
  - adequately heated to maintain the back-up N₂ system effectiveness, and
  - located at least 15 m from the wellbore.
BOP OPERATING CONTROLS

The accumulator system must include a set of operating controls that are readily accessible from the rig floor (driller’s position)/control cab and a set of remote operating controls (remote position) for each BOP and the HCR on the diverter / bleed-off line.

BOP UNIT/FLOOR CONTROLS

Each BOP component and the HCR in the diverter / bleed-off line must have a separate control located near the driller’s position.

Also, the BOP unit/floor operating controls must be as follows:

- capable of opening and closing each BOP component and the HCR in the diverter / bleed-off line,
- properly installed, readily accessible, correctly identified, and show function operations (i.e. open and close), and
- equipped with an accurate gauge indicating the accumulator system pressure.

BOP REMOTE OPERATING CONTROLS

Each BOP component and the HCR in the diverter / bleed-off line must have a separate control located at the remote position (typically located at the accumulator).

Also, the BOP remote operating controls must be as follows:

- capable of opening and closing each BOP component and the HCR in the diverter / bleed-off line,
- properly installed, correctly identified, and show function operations (i.e. open and close),
- be readily accessible and be equipped with an accurate gauge to determine the accumulator system pressure,
- located a minimum of 15 m from the well,
- readily accessible and housed to ensure that the remote controls can be protected from the well in the event of an uncontrolled flow, and
- adequately heated

MASTER HYDRAULIC CONTROL MANIFOLD LOCATION

The master hydraulic control manifold contains all of the four-way valves and regulators that control the open and close functions of the BOPs and the HCR on the diverter / bleed-off line. The four-way valve directs accumulator hydraulic fluid under pressure to the BOPs.
For critical sour wells, the master hydraulic control manifold must be located at the remote position.

For Class I to VI wells (non-critical), the master hydraulic control manifold should be located at the remote position (typically located at the accumulator).
Section 3 RECOMMENDED COILED TUBING PIPE SPECIFICATIONS

This section addresses the following topics:

1. coiled tubing grades,
2. evaluating the suitability of CT strings,
3. assessing mechanical strength,
4. determining CT string properties,
5. welding CT strings,
6. performing non-destructive examinations (NDEs),
7. performing automated dimensional inspections (ADIs),
8. performing hydrostatic proof testing of CT strings (non-operational),
9. ensuring CT string quality management,
10. performing CT string maintenance,
11. implementing a CT string-life management system, and
12. protecting CT strings against H₂S damage.

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.

3.1 COILED TUBING GRADES

Coiled tubing is categorized by its specified minimum yield strength (SMYS). Table 5 below summarizes a number of tube grades, with their associated mechanical properties.
### 3.2 Evaluating the Suitability of CT Strings

▶ A computer-based CT simulator or other documented calculation methods should be used to evaluate the suitability of CT strings for the proposed operation.

▶ The evaluation process shall determine the OD, wall thickness (taper), and material yield strength of the CT strings required for the proposed operation.

▶ All critically sour wells shall have the evaluation performed and documented.

### 3.3 Assessing Mechanical Strength

▶ The mechanical strength of the CT string shall be able to resist all applied forces and pressures with a specified margin of safety.

### 3.3.1 Calculation of VME Stress, Collapse Resistance, and Burst Resistance

▶ 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
3.3.2 **Maximum VME Stress**

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

3.3.3 **Calculated Collapse Resistance**

- The calculated collapse resistance of the tubing at the maximum expected tension should be greater than 125% of the maximum expected collapse pressure.
- Collapse resistance should assume zero CT internal pressure and either the measured maximum ovality or 3% ovality, whichever is greater.

3.3.4 **Overpull at the Maximum Depth Planned**

- Overpull at the maximum depth planned for the CT operation should be as follows:
  - 2,224 daN (5,000 lb), or
  - 125% of the tensile force required at the end of the CT string for the service, or
  - 125% of the tension required to operate a disconnect (if so equipped),
  - whichever is greater.

3.3.5 **Calculated Burst Resistance**

- The calculated burst resistance of the tubing should be greater than 125% of the maximum expected pump pressure.
- Burst resistance shall assume zero pressure outside the CT.

3.3.6 **Maximum Accumulated Fatigue**

- At the conclusion of the planned CT operation, the maximum accumulated fatigue in any section of the CT string should not exceed the limits imposed in this IRP in [Section 3.11: Implementing a CT String-Life Management System](#).

3.3.7 **CT Geometry Limits**

- A CT 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.
  - The tubing has ballooned more than 5% (that is measured OD > 1.05 x [Equation for 3% ovality](#)).
specified OD).

- The annular clearance between the minimum ID of the stripper bushing and the OD of the CT is less than 0.508 mm (0.020 inch); bushing may be changed out to provide necessary clearance.
- The ovality is more than 5%.

### 3.4 DETERMINING CT STRING PROPERTIES

#### 3.4.1 CHEMICAL COMPOSITION FOR CT STRINGS

##### NON-SOUR SERVICE

- The chemical composition of CT material for non-sour service should meet the manufacturer’s product specifications.

##### SOUR SERVICE

- The chemical composition of CT material for sour service should meet the product specifications listed in the Table 6 below.

<table>
<thead>
<tr>
<th>Element</th>
<th>Minimum (wt%)</th>
<th>Maximum (wt%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbon</td>
<td>0.05</td>
<td>0.16</td>
</tr>
<tr>
<td>Chromium</td>
<td>0.45</td>
<td>0.70</td>
</tr>
<tr>
<td>Copper</td>
<td>N/A</td>
<td>0.40</td>
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<tr>
<td>Manganese</td>
<td>0.50</td>
<td>1.00</td>
</tr>
<tr>
<td>Molybdenum</td>
<td>N/A</td>
<td>0.23</td>
</tr>
<tr>
<td>Nickel</td>
<td>N/A</td>
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</tr>
<tr>
<td>Phosphorous</td>
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<tr>
<td>Silicon</td>
<td>0.30</td>
<td>0.50</td>
</tr>
<tr>
<td>Sulphur</td>
<td>N/A</td>
<td>0.005</td>
</tr>
</tbody>
</table>

##### 3.4.2 MECHANICAL PROPERTIES OF CT STRINGS

##### NON-SOUR SERVICE

- The full-body material mechanical properties of CT strings for non-sour service should meet the CT manufacturer’s product specifications.
SOUR SERVICE

Coiled tubing used in sour service shall meet the following minimum requirements (unless otherwise demonstrated fit-for-purpose), which are based on the requirements in ANSI/NACE Standard MR0175/ISO15156 as interpreted for the specific characteristics of coiled tubing:

- Maximum hardness shall be not greater than 22 HRC (or equivalent hardness scales).
- The maximum permissible hardness shall not be exceeded at any point in the as-manufactured sour service CT string.
- Steel coils used to manufacture coiled tubing shall be produced by the hot-rolling process only.
- The longitudinal weld seam shall be annealed after welding.
- The tube body shall be stress-relieved after all tube manufacturing cold working.

Coiled tubing used in sour service should meet the following minimum requirements:
- Microhardness should be measured by the CT manufacturer from tube samples taken from the beginning and end of each string of tubing.
- Microhardness tests should be performed in the as-milled (non-spooled) condition.
- A minimum of nine microhardness measurements should be made on each sample: three measurements on the longitudinal weld seam, three measurements in the longitudinal weld seam heat-affected zone (HAZ), and three measurements in base metal.

TENSILE PROPERTIES

- Actual yield strength and tensile strength shall be measured by the CT manufacturer from tube samples taken from the beginning and end of the string of tubing.

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

- Tests shall be performed according to the latest revision of ASTM A-370 and ASTM E8.
Yield strength should be determined by the 0.2% offset method. However, for used coil strings, this 0.2% offset method can give unrealistically low values due to the influence of residual stresses on the stress-strain curve. Therefore, for tensile tests on used tubing, the 1% pre-strain and offset method should be used.

**MICRO-HARDNESS TESTS**

- 500 gram (or equivalent) micro-hardness tests of sections from full-tube specimens shall be performed in accordance with the requirements of ASTM E384 for at least three points in each of the following zones:
  - seam weld,
  - seam-annealed area, and
  - base metal.
- All hardness conversions from one scale to another shall be performed according to ASTM E140.

**FLARE AND FLATTENING TESTS**

- Flare and flattening tests shall be performed on full-tube specimens in accordance with either the requirements of ASTM A450 as a minimum, or the CT manufacturer's documented specification requirements, whichever is more stringent.

### 3.4.3 Hardness of Welds in CT Strings

**BIAS WELDS**

- For bias welds, Rockwell hardness as per ASTM E18 in both the weld and HAZ shall not exceed the maximum hardness specified for the CT string.

**Tube-to-Tube Butt Welds**

- For tube-to-tube butt welds, Rockwell hardness as per ASTM E18 for at least four equally spaced points around the weld circumference in both the weld and HAZ shall not exceed that of the maximum specified hardness of the adjacent parent base metal.

**Longitudinal Welds**

- For longitudinal welds, Rockwell hardness as per ASTM E18 in both the weld and HAZ shall not exceed the maximum specified hardness for the adjacent parent base metal.
3.5 **WELDING CT STRINGS**

**3.5.1 BUTT WELD PROHIBITION**

- Unless there is prior approval from the customer, a CT string containing a butt weld shall not be used for well servicing Class II/drilling Class III and IV, or well servicing Class III/drilling class V and VI sour service.

- A CT string containing a butt weld shall not be used for critical sour service.

**3.5.2 FLAG WELD PROHIBITION**

- CT strings shall not contain any welds intended to repair only the tubing surface or to mark the surface (commonly referred to as “flag welds”).

**3.5.3 RECORDS**

- Records of all tube-to-tube butt welds should be maintained for the life of the string.

- The welding service shall maintain a record (weld log) for each weld, which documents the procedure used and the identification of the welder or welders who performed the weld.

**3.5.4 WELDED TUBING CONNECTION AT THE CT REEL**

- If the tubing connection to the CT reel plumbing is a welded fitting, the weld shall conform to a qualified WPS performed by a welder in accordance with the welder qualifications and procedures specified above.

- Non-destructive examination (NDE) inspections shall be performed only after the weld cools to ambient temperature.

- No relevant indications (as per *ASNT SNT-TC-1A*) are permitted, regardless of size.

- Unacceptable welds shall be cut out and re-welded.

- All welds on tubing connections shall successfully pass either of the following tests:
  - wet fluorescent magnetic particle inspection (MT) as per *ASTM E 709*, or
  - liquid penetrant inspection (PT) as per *ASTM E 165*.

**3.5.5 WELDER QUALIFICATIONS**

For welder qualifications, see [Section 1.3.4: Welder Qualifications] of this IRP.
3.6 **Performing Non-Destructive Examinations (NDEs)**

NOTE: Additional recommended and best practices on NDE of CT strings are summarized in Appendix B.

3.6.1 **NDE of CT Strings**

▶ An inspector certified to ASNT Level III for the applicable discipline shall approve all NDE, in accordance with documented NDE procedures.

▷ The approved NDE procedures should be available to the purchaser before the NDE is performed. If requested, the NDE service shall provide documentation for each NDE procedure that does the following:

1. describes the test parameters,
2. includes the procedure number and revision level,
3. describes the acceptance criteria, and
4. includes the Level III inspector's approval signature.

▷ All NDE should be performed by a technician/inspector certified as a minimum to a Level II inspector status in the applicable inspection discipline in accordance with the latest edition of ASNT SNT-TC-1A or comparable customer-accepted standard.

▷ Documentation should be available to confirm calibration is current.

3.6.2 **Full-Length NDE of CT Strings**

**NEW CT STRINGS**

▶ The CT manufacturer shall perform automated NDE on the full length of the entire body of the CT string and the weld line for material discontinuities during manufacture.

**USED CT STRINGS**

▷ Whenever NDE is requested on the full length of the entire body of a used CT string, it should be completed after a satisfactory hydrostatic test as described in this IRP in Section 3.8: Performing Hydrostatic Proof-Testing of CT Strings (Non-Operational) and before mobilizing the string for the next service operation.

▶ For intervention in all critical sour wells, an assessment shall be carried out to determine whether a full length NDE inspection is required. This should include, but not be limited to, operation complexity, well parameters, environmental concerns, and previous history of the string.
3.6.3 **NDE OF BIAS OR BUTT WELDS IN CT STRINGS**

- All well servicing Class I/drilling Class I and II operation welds should be inspected.
- All well servicing Class II and III; drilling Class III, IV, V, and VI; and critical sour operation welds shall pass the required inspection.
- Rejected welds shall be completely removed (cut out) and rewelded. Removing a flaw from a weld by grinding and filling in or overlaying the flaw is unacceptable.
- All bias welds shall be 100% volumetrically inspected by radiographic testing (RT).
- All well servicing Class II and III and drilling Class III, IV, V, and VI butt welds shall be 100% volumetrically inspected by RT or ultrasonic shear wave testing (UT), with additional liquid penetrant testing (PT) for surface defects.
- All NDE inspections of bias or butt welds shall be performed with the weld at ambient (room) temperature.

3.7 **PERFORMING AUTOMATED DIMENSIONAL INSPECTIONS (ADIs)**

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

3.7.1 **GENERAL REQUIREMENTS**

- ADI of a CT string should be performed to a written procedure.
- The ADI equipment should be 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 such as MS Excel or MS Word.
- The ADI equipment should include an electronic depth counter that meets the following requirements:
  - capability of measuring the full length of the CT string,
  - measurement resolution of ±0.1 foot or better, and
  - tubing length accuracy of ±0.5%.
- The ADI equipment should be calibrated to appropriate standards prior to and immediately following the inspection.
- The ADI equipment should be 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 CT string.

- If the ADI equipment is capable of alerting the operator or marking the location on the CT 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 CT through the inspection equipment should be adjusted to provide multiple signals from a given inspection location on the tubing.

### 3.7.2 Minimum Acceptable Outputs from Measurements

The minimum acceptable outputs from automated OD measurements are the following at each measurement location:

- maximum OD (measured),
- minimum OD (measured),
- average OD (calculated), and
- ovality (calculated).

The minimum acceptable output from automated wall thickness measurements is average wall thickness at each measurement location.

### 3.7.3 Measurement Locations

- The OD and wall thickness should be measured on at least three radials equally spaced around the tubing circumference.

- All dimensional measurements should be made at regularly spaced axial locations along the string.

- The maximum axial spacing between measurement locations should be 5.0 feet.

### 3.7.4 Measurement Accuracy

Minimum acceptable measurement accuracy for dimensional measurements should be as follows:

- OD = 0.010 inch
- average wall thickness = 0.005 inch

### 3.7.5 Dimensional Inspection Reports

- The complete results of all ADI performed on a CT string should be documented in a dimensional inspections report completed by the technician who performed the inspection.

- The axes of plots and headings for tabular data should be clearly identified and labelled with the corresponding units.
The report should contain the following content, as a minimum:

- serial number or inventory control number of the CT string;
- nominal OD, length, specified wall thickness, and material of the CT string;
- ADI methods used;
- details on 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 CT string;
- output from the inspection equipment for scans of the reference standards;
- results from ADI of the CT string with the location of each indication exceeding the preset limits clearly identified;
- disposition of each indication;
- printed name and signature of the technician performing the inspection and the date of the inspection.

### 3.7.6 Dimensional Inspection System Capability Records

The ADI service provider should maintain inspection system records verifying system capabilities.

The verification and records should cover, as a minimum, the following criteria:

- coverage calculation (that is scan plan),
- capability for the intended OD and wall thickness,
- repeatability,
- threshold setting parameters,
- ADI system operating procedures,
- ADI equipment description, and
- ADI personnel qualification information.

### 3.8 Performing Hydrostatic Proof-Testing of CT Strings (Non-Operational)

- All CT strings shall be hydrostatically tested by the CT manufacturer before shipment and subsequently as required by the end user (service company).
- All butt welds should have an initial hydrostatic test before operations begin.
3.8.1 **PLUMBING OR PIPING SYSTEM**

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

3.8.2 **TEST PRESSURE FOR CT STRINGS**

- The required hydrostatic test pressure for new CT strings shall be at least

\[
P_{HT} = \frac{1.60 \times \sigma_{Y_{\min}} \times t_{\min}}{OD}
\]

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).

- Hydrostatic testing pressures exceeding 103 MPa shall be previously agreed upon by all parties involved.

3.8.3 **TEST MEDIUM / FLUIDS**

- The pressurizing medium for all tests should be water or a water/antifreeze mixture having pH greater than 7 and less than 9 (that is 7 < pH < 9).

3.8.4 **PRESSURE-HOLDING PERIODS**

- Each pressure test should include a pressure-holding period of a minimum of 15 minutes.

- The timing of the pressure-holding period should not start until the following has occurred:
  - the test pressure has been reached and stabilized,
  - the CT string and the pressure monitoring gauge/chart recorder have been isolated from the pressure source, and
  - the external surfaces have been thoroughly dried.

3.8.5 **ACCEPTANCE CRITERIA**

- The CT string shall show no visible leaks under the test pressure and any pressure drops evident on the pressure recording device during a hold period should be less than 3%.
3.8.6 PRESSURE MEASUREMENT AND RECORDING

- All pressure testing should be performed with calibrated pressure gauges/transducers that have an accuracy of 0.5% of full scale and recorded on a calibrated chart if applicable.

- Pressure gauges and charts should be chosen such that the test pressures fall between 25% and 75% of the full scale of the instrument.

- Charts should be of sufficient scale to clearly show the tests.

- The recording device clock (time base) should 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 should be provided with the CT string’s records.

Each pressure test chart should be documented with the following:

- CT string’s description;
- CT 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).

3.8.7 REMOVAL OF TEST FLUID

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

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

3.8.8 DRIFTING / GAUGING OF CT STRINGS

- All CT strings shall be drifted/gauged with a metal or nylon ball by the CT manufacturer before shipment and as required for the service. Table 7 below shows the acceptable diameter of the drift ball.

Note: The CT specified in the table below is manufactured in imperial units and thus the metric conversions are for information only.
Table 7: Required Drift / Gauge Ball Diameters

<table>
<thead>
<tr>
<th>CT Specification (Imperial)</th>
<th>Drift Ball</th>
</tr>
</thead>
<tbody>
<tr>
<td>OD (inches)</td>
<td>Wall, t (inches)</td>
</tr>
<tr>
<td>0.750</td>
<td>All</td>
</tr>
<tr>
<td>1.000</td>
<td>All</td>
</tr>
<tr>
<td>1.250</td>
<td>All</td>
</tr>
<tr>
<td>1.500</td>
<td>t ≤ 0.175</td>
</tr>
<tr>
<td>1.500</td>
<td>t &gt; 0.175</td>
</tr>
<tr>
<td>1.750</td>
<td>t ≤ 0.145</td>
</tr>
<tr>
<td>1.750</td>
<td>t &gt; 0.145</td>
</tr>
<tr>
<td>2.000</td>
<td>t ≤ 0.175</td>
</tr>
<tr>
<td>2.000</td>
<td>t &gt; 0.175</td>
</tr>
<tr>
<td>2.375</td>
<td>All</td>
</tr>
<tr>
<td>2.625</td>
<td>All</td>
</tr>
<tr>
<td>2.875</td>
<td>All</td>
</tr>
<tr>
<td>3.250</td>
<td>All</td>
</tr>
<tr>
<td>3.500</td>
<td>All</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>CT Specification (Metric)</th>
<th>Drift Ball</th>
</tr>
</thead>
<tbody>
<tr>
<td>OD (mm)</td>
<td>Wall, t (mm)</td>
</tr>
<tr>
<td>19.05</td>
<td>All</td>
</tr>
<tr>
<td>25.4</td>
<td>All</td>
</tr>
<tr>
<td>31.75</td>
<td>All</td>
</tr>
<tr>
<td>38.10</td>
<td>t ≤ 4.445</td>
</tr>
<tr>
<td>38.10</td>
<td>t ≤ 4.445</td>
</tr>
<tr>
<td>44.45</td>
<td>t ≤ 3.683</td>
</tr>
<tr>
<td>44.45</td>
<td>t ≤ 3.683</td>
</tr>
<tr>
<td>50.80</td>
<td>t ≤ 4.445</td>
</tr>
<tr>
<td>50.80</td>
<td>t ≤ 4.445</td>
</tr>
<tr>
<td>60.32</td>
<td>All</td>
</tr>
<tr>
<td>66.75</td>
<td>All</td>
</tr>
<tr>
<td>73.02</td>
<td>All</td>
</tr>
<tr>
<td>82.55</td>
<td>All</td>
</tr>
<tr>
<td>88.90</td>
<td>All</td>
</tr>
</tbody>
</table>

3.9 ENSURING CT STRING QUALITY MANAGEMENT

3.9.1 MANUFACTURER QUALITY MANAGEMENT SYSTEM

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

3.9.2 CT STRING MANUFACTURING

MANUFACTURING QUALITY PLAN

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

The MQP should cover all the activities required by both the CT manufacturer’s in-house quality inspectors and any inspection points required by the customer.

The quality plan 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.

▷ If the customer requires on-site quality control, the following apply:
• provisions should be made for the customer or customer’s third party inspector (TPI) to monitor and witness the specific inspection and test activities, and
• an advance notification period should be initiated during which the CT manufacturer should provide notice to the customer to allow the customer representatives to participate as required in the listed inspection points.

TRACEABILITY DURING MANUFACTURING

▷ The CT string manufacturer shall maintain traceability on all CT strings during manufacturing.

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

NON-CONFORMANCE/REQUESTS FOR EXCEPTION

▷ The CT manufacturer should ensure that all non-conforming products are brought into compliance with applicable requirements.

▷ The CT manufacturer shall not allow non-conformances to be labelled “use-as-is” without first obtaining customer acceptance.

3.9.3 CT STRING QUALITY RECORDS

▷ The CT manufacturer shall maintain for a minimum of three years the following information for each CT string:
  • CT manufacturer’s name;
  • date and location of manufacture;
  • manufacturer’s serial number or other inventory control number for the string;
  • certificate of compliance (COC)/statement of conformity to product specifications, and MQP;
  • total length of the CT 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 (2 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 CT string before storage/shipment;
• procedure and chemicals used to protect the string OD and ID from storage corrosion;
• weld log containing, as a minimum, location of each bias weld, and location of each tube-to-tube butt weld, if applicable;
• WPS/PQR numbers;
• welder identification;
• report of NDE on each weld signed and dated by Level II NDE technician performing the examination.

3.9.4 **CT STRING POST-PRODUCTION RECORDS**

**TRACEABILITY OF CT STRINGS**

► The end user of a CT string shall ensure traceability is maintained on the CT string.

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

► Traceability of CT strings shall be maintained to the following:
  • manufacturer’s CMTRs,
  • quality records/data book, and
  • end user’s inspection and test reports, maintenance records, and operating data.
CT STRING DOCUMENTATION / RECORDS – END USER

▷ The end user of a CT string should develop and maintain documentation for each CT string recording the information below.

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

▷ For critical sour well servicing, the following shall be developed and maintained:
  • inspection reports,
  • visual,
  • nde,
  • dimensional,
  • hydrostatic test reports,
  • each CT operation performed with a cross reference to appropriate CT string life management files,
  • accumulated fatigue for each segment of the string on computerized managed strings,
  • exposure to acid,
  • composition of the acid,
  • steps taken to protect CT against corrosion before a CT operation and to neutralize corrosion after the CT operation,
  • exposure to H₂S and CO₂,
  • exposure to abrasive fluids,
  • fluids pumped for each CT operation,
  • purging records,
  • corrosion protection records, and
  • storage records.

VELOCITY STRING INFORMATION FOR INSTALLATION AND REMOVAL

• butt welds in string
• downhole BHA, nipples or other completion equipment in string
• fatigue history of string when installed
• coil info, i.e. OD, length, grade (yield stress of material), and wall thickness

3.10 Performing CT String Maintenance

▷ The end user should use a documented program for maintenance of CT strings.
The CT string maintenance program should address the tasks defined in this section.

### 3.10.1 CLEANING THE ID SURFACE OF THE CT STRING

#### REQUIREMENT FOR CLEANING

The individual coil end user should use due diligence to ensure the coiled tubing string being used is properly cleaned before each operation, as required to ensure it is fit for purpose.

#### GENERAL PROCEDURE

The general procedure for cleaning the ID of a CT string (no internal cable) should include the following as a minimum:

- mechanical cleaning to remove heavy rust and scale (skip for CT string containing cable),
- flushing with clean fresh water,
- chemical cleaning to remove light rust and scale, and
- neutralizing the ID.

#### MECHANICAL CLEANING

The procedure for mechanical cleaning of CT strings should include the following steps as a minimum:

1. Select two mechanical CT cleaning pigs—common wiper darts and foam plugs are not acceptable—appropriately designed and sized for cleaning the coiled tubing ID.
2. Insert the two cleaning pigs into the CT string separated by approximately the length of one wrap around the reel.
3. Pump both cleaning pigs through the CT string using clean fresh water or a water/antifreeze mixture. Pump at a flow rate that will ensure turbulent flow.

#### TUBING FLUSHING

When the trailing cleaning pig exits the CT string, continue to pump clean fresh water or a water/antifreeze mixture equal to at least one full string volume or until the discharge is suitably clear, whichever volume is greater. Pump at a flow rate that will ensure turbulent flow.
CHEMICAL CLEANING

▷ The procedure for chemical cleaning of CT strings should include the following:
  • Use hydrochloric acid (HCl) or other chemical designed to chemically clean the ID of the string.
  • Use an adequate volume of chemical.
  • Subsequently, switch to clean fresh water or water/antifreeze mixture and continue pumping until the pH of the discharge is greater than six (that is pH > 6.0).

NEUTRALIZING THE TUBING SURFACE pH

▷ After chemically cleaning with acid, the tubing surface should be neutralized to eliminate any low pH spots that can lead to corrosion.

▷ The procedure for neutralizing the tubing surface pH should include the following:
  • The neutralizer should have pH greater than nine and less than 11 (that is 9 < pH < 11).
  • Use an adequate volume of neutralizer.
  • Subsequently, 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 (that is 7 < pH < 9).

PREPARATION FOR STORAGE

▷ If the freshly cleaned CT string will not be used within 48 hours, apply internal and external corrosion inhibitors designed for that purpose.

3.10.2 Corrosion Protection for CT Strings

EXTERNAL CORROSION INHIBITION

▷ If external corrosion protection is requested, the CT manufacturer shall uniformly apply a full-body coating of corrosion inhibitor to the exterior of the CT string.

INTERNAL CORROSION INHIBITION

▷ If internal corrosion protection is requested the following shall apply:
  • The volume of the inhibitor shall be adequate to coat the entire surface of the CT string.
After the hydrostatic test, the CT manufacturer shall trap a volume of inhibitor between two foam plugs and then pump the combination around the tubing with nitrogen (the objective is to apply a uniform coating to the interior surface of the tubing).

The nitrogen flow rate shall be as low as practical to maximize the contact between the inhibitor and the ID surface. The manufacturer shall select foam plugs that fit tightly inside the ID of the tubing.

**NITROGEN INSIDE THE CT STRING**

- If required by the CT string purchase specification, the CT manufacturer should pressurize the CT string with nitrogen after internal corrosion inhibitor coating.

The positive nitrogen pressure will prevent evaporation of the inhibitor, minimize the oxygen level inside the CT string, and prevent moisture and other contaminants from entering the string. Oxygen is a primary contributor to internal corrosion.

### 3.10.3 MANAGING SLACK FOR INTERNAL ELECTRIC CABLE

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

- If electrical cable is protruding from the end of the CT string before a CT operation, the end user should verify that the length of cable inside the CT string is at least 1% greater than length of the CT string. Otherwise, the end user should attempt to pump the excess cable into the CT string.

### 3.11 IMPLEMENTING A CT STRING-LIFE MANAGEMENT SYSTEM

#### 3.11.1 WELL SERVICING CLASS I WELLS / DRILLING CLASS I AND II

- The CT string-life management system for well servicing Class I/drilling Class I and II wells should be adequate to prevent a string failure of the CT string due to accumulated low-cycle fatigue.

#### 3.11.2 WELL SERVICING CLASS II/DRILLING CLASS III AND IV, WELL SERVICING CLASS III / DRILLING CLASS V AND VI, AND CRITICAL SOUR WELLS

- The CT string-life management system for well servicing Class II/drilling Class III and IV, well servicing Class III/drilling Class V and VI, and critical sour wells shall be a computer-based system for tracking the cumulative low-cycle fatigue in each segment of a CT string.

- The maximum segment length for tracking CT fatigue in this manner shall be 15.2 m (50 feet).

The fatigue limits below apply to computer-based systems only.
FATIGUE LIMITS FOR BASE TUBING

- The end user should remove a CT string from further service operations if the accumulated fatigue in the base tubing of any section of the string exceeds the applicable percentage of its predicted working life for the given service category.

- For non-sour service, the accumulated fatigue in the base tubing of any section of the string should not exceed 100% of the predicted working life.

- For sour service with continuous application of H2S inhibitor during a sour CT operation, the accumulated fatigue in the base tubing of any section of the string should not exceed 40% of its predicted life to failure in air under the same pressures and bending strains.

- For tubing not protected by H2S inhibitor during the sour CT operation, the accumulated fatigue in the base tubing should not exceed 15% of the predicted life to failure in air under the same pressures and bending strains.

It is recognized that work is ongoing to develop more accurate fatigue limits for various coiled tubing grades, both with and without inhibitor protection, in sour environments. As additional data become available the fatigue limits applied may change.

FATIGUE LIMITS FOR WELDS

- The end user should remove a CT string from further service operations, if the accumulated fatigue in a weld exceeds the applicable percentage limit of the predicted working life for the adjacent base metal.

- A bias weld between strips of equal thickness should be retired from service before its accumulated fatigue reaches 90% of that in the adjacent base metal.

- A bias weld between strips of different thickness should be retired from service before its accumulated fatigue reaches 80% of that in the adjacent base metal.

- A tube-to-tube butt weld should be retired from service before its accumulated fatigue reaches the accumulated fatigue for the adjacent base metal tubing shown in the Table 8 below.

Table 8: Butt Weld Fatigue Limit

<table>
<thead>
<tr>
<th>Butt Weld Type</th>
<th>Allowable Fatigue</th>
</tr>
</thead>
<tbody>
<tr>
<td>Uniform wall thickness – orbital</td>
<td>45%</td>
</tr>
<tr>
<td>Uniform wall thickness – manual</td>
<td>35%</td>
</tr>
<tr>
<td>Different wall thickness – orbital</td>
<td>25%</td>
</tr>
<tr>
<td>Different wall thickness – manual</td>
<td>15%</td>
</tr>
</tbody>
</table>
FATIGUE LIMITS FOR MECHANICAL SPLICES

▷ The end user of a mechanical splice (tube-to-tube connector) for a CT string shall be responsible for determining the fatigue limit for the mechanical splice before the intended service operation.

▷ A mechanical splice should be retired from service before its accumulated fatigue reaches this predetermined limit.

3.12 PROTECTING CT STRINGS AGAINST H₂S DAMAGE

▷ For sour service CT operations, the end user should use a documented method for minimizing damage to the CT string from hydrogen embrittlement (HE), hydrogen induced cracking (HIC), and sulphide stress cracking (SSC).

3.12.1 WELL SERVICING CLASS II SOUR CONDITIONS WELLS/DRILLING CLASS III AND IV SOUR CONDITIONS WELLS (DRILLED UNDERBALANCED)

▷ For well servicing Class II sour conditions wells/underbalanced-drilled drilling Class II and IV sour wells, the end user should apply an H₂S inhibitor to the exterior of the CT string.

Addition of an H₂S scavenger to the wellbore fluid may be an acceptable alternative to application of an H₂S inhibitor if the H₂S content of the treated fluid is less than 0.1% by volume.

3.12.2 WELL SERVICING CLASS III SOUR CONDITIONS WELLS / DRILLING CLASS V AND VI SOUR CONDITIONS WELLS (DRILLED UNDERBALANCED) AND CRITICAL SOUR WELLS

▷ For well servicing Class III sour conditions, critical sour wells, and drilling Class III and IV sour conditions wells drilled underbalanced, the end user shall apply an H₂S inhibitor to the exterior of the CT string.

Addition of an H₂S scavenger to the wellbore fluid is not an acceptable substitute for application of an H₂S inhibitor.

H₂S INHIBITOR PROPERTIES

▷ The H₂S inhibitor should be a fit-for-purpose anti-cracking agent. Products that only protect the CT against surface corrosion are not recommended.

▷ The H₂S inhibitor should be compatible with the other fluids used during the operation. The end user should be able to demonstrate such compatibility before starting the CT operation.

▷ The H₂S inhibitor should be 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 such compatibility before starting the CT operation.
H₂S INHIBITOR APPLICATION

▷ The end user should use a documented method for applying the H₂S inhibitor to the exterior of the CT during the CT operation.

▷ The end user should be able to demonstrate that the application method effectively coats the exterior of the CT with H₂S inhibitor.

H₂S INHIBITOR EFFECTIVENESS

▷ The end user should be able to demonstrate the effectiveness of the H₂S inhibitor and its application method for protecting the CT string against damage from HE, HIC, and SSC in the expected wellbore conditions during the CT operation.

▷ Inhibitor qualification testing should measure the following:
  - ductility of the treated CT material exposed to the sour conditions,
  - rate of hydrogen diffusion through the treated CT material,
  - SSC resistance of the treated CT material,
  - HIC resistance of the treated CT material, and
  - low cycle fatigue life with strain at least 2% and strain rate at least 1.0 sec⁻¹ after exposure to the wellbore conditions.
Section 4 RECOMMENDATIONS ON FLUIDS AND CIRCULATING SYSTEMS

This section addresses the following topics:

1. other IRPs on fluids and circulating systems,
2. critical sour well servicing operations,
3. critical sour underbalanced drilling operations, and
4. use of air.

4.1 OTHER IRPs ON FLUIDS AND CIRCULATING SYSTEMS

The following IRPs have been developed that address many aspects of fluids and circulating systems:

- IRP 1: Critical Sour Drilling,
- IRP 4: Well Testing and Fluid Handling,
- IRP 8: Pumping of Flammable Fluids,
- IRP 14: Non Water Based Drilling and Completion/Well Servicing Fluids, and
- IRP 18: Fire and Explosion Hazard Management.

Consult these IRPs for recommended practices about fluids and circulating systems for CT operations.

In addition to the IRPs above, recommended practices related to fluids and circulating systems have been developed for critical sour operations.

- The recommended practices of this IRP as well as IRPs 1, 4, 8, 14, and any other relevant IRPs shall be followed.

- If there appears to be a conflict among these recommendations, the most stringent recommendation will apply.

Information on fluids and circulating systems for overbalanced drilling of critical sour wells can be found in IRP 1: Critical Sour Drilling.

This fluids and circulating systems section contains additional requirements for critical sour wells for well servicing and underbalanced drilling, over and above the requirements laid down in IRPs 1, 4, 8, and 14. These are listed to ensure consistency of standards with IRP 2: Completing and Servicing Critical Sour Wells and 6, so that the requirements for coiled tubing units, service rigs, and drilling rigs are in agreement.
For bonding and grounding requirements see Section 1.5.2: General Safety Requirements.

4.2 CRITICAL SOUR WELL SERVICING OPERATIONS

4.2.1 SURFACE EQUIPMENT

PRESSURE RATING OF SURFACE EQUIPMENT

- Circulating pumps, manifolds, discharge lines, and return lines shall have a working pressure equal to or greater than 1.2 times the shut-in tubing pressure.
- Design working pressure limits of equipment shall be considered for equipment selection to ensure that it is capable of safe operations at the anticipated pressures.

BACK-UP PUMPS

- When a hard shut-in cannot be done during pumping operations, a back-up pump with manifold is required on location to maintain control of the well, because a pump failure could lead to uncontrolled flow.
- For wells that can be shut in, contingency plans shall be in place for a back-up pump with manifold to be brought to location should the fluid pump fail.

FLUID PUMP

- The fluid pump shall have a discharge rate of sufficient capability (pump rate and pressure) to control the well.
- For winter operation, the pump, manifold, and lines shall be adequately heated to prevent freezing.

FLUID STORAGE TANK

- The fluid storage tank shall provide for accurate fluid gauging.
- For winter operation, the tank shall be adequately heated to prevent freezing. For example, fluid storage tanks with properly maintained steam coils will prevent freezing and steam contamination of fluid.
- 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.
CLOSED SYSTEM CIRCULATION

- Fluid-gas separators (rig degassers) shall not be used on open rig tanks, as sour effluent cannot be emitted to atmosphere.
- 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.

SOUR FLUID STORAGE

- Sour fluid storage tanks are required for storage of all sour fluids.
- Storage tanks containing sour fluids or sour gasified fluids shall be as follows:
  - be grounded and bonded,
  - be purged before storing sour fluids,
  - have a mechanical gauge for gauging the tank level,
  - be equipped with connections for circulating the tank to add scavenger or for unloading,
  - be equipped with steam coils during winter operations to prevent fluids from freezing and steam contamination, and
  - have a flame arrestor installed on the storage tank vent line at the base of the flare stack.

COMPLETION AND WORKOVER FLUIDS

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

- Caution should be taken while using hydrocarbon fluids as risk to well control can be increased by reduced warning signs of kicks, increased solubility of H2S, and slowed reaction time of scavengers.
- Caution should be taken as injection of a hydrocarbon or flammable fluid into an air-filled or partially air-filled well may result in favourable conditions for explosions or fires given a suitable ignition source.

4.2.2 DISSOLVED SULPHIDE

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

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

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.

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

4.2.3 COMPLETION FLUID VOLUME AND STORAGE

All fluid volumes on location shall be monitored and recorded to ensure the following:

The volume of usable completion fluid to control the well = The hole volume + A SURFACE BACK-UP VOLUME OF 100% OF THE HOLE VOLUME + TANK BOTTOM STRIPPER

The fluid volumes 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, and
- before and after tripping.

Before starting an operation, have 200% of active hole volume on surface and maintain 100% of active hole volume on surface at all times.

Kill fluid density shall provide a minimum of 1,400 kPa overbalance of the formation pressure.

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

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

4.2.4 HANDLING

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

Transportation of dangerous goods (TDG), workplace hazardous materials information system (WHMIS), and applicable provincial occupational health and safety regulations must be followed.
4.3 CRITICAL SOUR UNDERBALANCED DRILLING OPERATIONS

The design of circulating media systems is an integral part of pre-planning and programming for a critical sour underbalanced well.

4.3.1 MEDIA PROPERTIES

Flammability and Explosive Limits

- Explosive limits shall be established for all circulating media systems that have the potential to introduce oxygen into the circulating stream.
- If explosive limits are not clearly defined, systems which have the potential to introduce oxygen to the circulating stream shall not be used.
- Explosive limits shall be documented and posted next to the oxygen monitoring system for all circulating streams that contain oxygen.
- Steps shall be taken to ensure that these limits are never reached throughout underbalanced drilling operations.

The circulating media for purposes of this IRP include both injected and produced fluids as well as their mixtures.

Hydrocarbons, when mixed with appropriate levels of oxygen, result in an explosive condition. In a closed circulating system where no oxygen is contained in the circulating stream, explosive conditions are not present. However, oxygen may be introduced into the circulating stream at specific points such as at the gas injection equipment. As the percentage of oxygen within the circulating stream increases, the susceptibility of the mixture to ignition increases. The presence of H₂S reduces the oxygen levels required to create a potentially explosive condition (as described in the SPE Paper 37067: High Pressure Flammability of Drilling Mud/Condensate/Sour Gas Mixtures in De-oxygenated Air for Use in Underbalanced Drilling).

HYDRATES

When exposed to the appropriate pressure and temperature conditions, hydrates can form in a gas well, or a high gas content oil well, as it is being drilled underbalanced. Hydrates limit the ability to produce fluids, inject fluids, and ultimately control the well safely.

- Measures shall be taken to prevent hydrate formation unless it can be proven that hydrates cannot be formed in the gas stream expected to flow from the well while drilling underbalanced. These measures will include, but are not limited to, the use of surface line heaters and the injection of fluids to
appropriately control the freezing point of the circulated/produced fluid stream.

Hydrate plugs are an ice-like crystalline structure made up of water and hydrocarbon gases. Due to the chemical composition of this structure, its freezing point is well above the normal freezing point of fresh water. These plugs can form when a gas/water mixture flows through a pressure drop that causes a localized cooling effect. A solid structure may start building up, and if not controlled can completely bridge off the flowing area. Pressure drops may occur at various locations within a circulating path such as inside tubulars, across choke manifolds, across flow path diameter changes, BOPs, etc.

- If methanol is introduced into the system, consideration shall be given to changes in flammability limits and the potential for a sudden release of the hydrate plug.

**Carrying Capacity**

- A multi-phase flow simulation of the returning flow stream shall be done to ensure adequate hole cleaning through proper design and implementation of the underbalanced circulation system.

- The flow regime of multi-phase circulating streams is typically more complex than for single-phase circulating streams. To ensure adequate hole cleaning while drilling with a multi-phase system, a proper understanding of cuttings transport in this environment is necessary. Inadequate hole cleaning could result in the circulation returns path becoming packed off, limiting the ability to circulate and thereby resulting in a potential reduction of well control. Loss of the ability to circulate due to cuttings pack-off will also likely result in a stuck drill string.

**Separation Qualities**

- Steps shall be taken to ensure that separation of solids, gases, and liquids at surface is sufficient such that the ability to effectively circulate liquids downhole is not compromised.

Separation of oil, water, gases, and solids contained in the circulating media at surface is necessary during an underbalanced drilling operation. Inadequate separation may result in a variety of problems including inconsistencies in circulating fluid properties that result in flow modelling inaccuracies, loss of accurate injection/production volume measurements, and fluid carryover to the flare stack.

*Formation of Emulsions*

Formation of emulsions may be a concern with specific circulating media/produced fluids combinations. This may result in pumping difficulties, which in extreme cases could result in plugged suction lines. Fluid density control may also be compromised when emulsions form.
Operational practices such as the use of demulsifiers, line heaters, and constant removal of emulsified fluids should be considered where emulsion formation is anticipated to be a problem.

If demulsifiers or other chemicals are introduced into the system, consideration shall be given to changes in flammability limits.

Use of Viscosified or Hydrocarbon-Based Fluids

The use of viscosified or hydrocarbon-based fluids in underbalanced drilling operations may result in gas entrainment. Gas entrainment may result in vapour-locking of fluid pumps, lack of fluid density control, as well as recirculation of produced gases. Where the system is open to the atmosphere (such as open mud tanks, drill pipe on connections) entrained gas may break out, causing hazards to workers.

These areas shall be monitored and operations stopped if worker exposure limits are exceeded. Refer to Section 6.7 of IRP 6: Critical Sour Underbalanced Drilling.

Compatibility With Other Systems

The presence of acid gases (H$_2$S, CO$_2$), acid fluids, oxygen, and electrolytes in the circulating system can result in corrosive conditions. Corrosion of metals or degradation of rubbers, elastomers, and seals can lead to failure of components, which could result in safety or environmental concerns.

The chemical composition of any additives to be used in the circulating media shall be examined to ensure they do not contain constituents that could result in premature failure of elastomers, seals, etc., either alone or in combination with produced fluids. Refer to Section 6: Recommendations on Elastomeric Seals for detailed requirements.

If H$_2$S recirculation is anticipated, operational issues regarding H$_2$S compatibility with metallic components, elastomers, and fluids handling/storage equipment shall be addressed.

Sour fluids may be stripped of H2S by employing a properly designed scrubber system. Such a system is recommended for drilling fluids containing H2S that are to be reinjected into the wellbore.

4.3.2 Kill Fluids

Operational or safety considerations may require the killing of a well that is being drilled underbalanced.
A minimum of 1.5 hole volumes of kill fluid shall be available at all times for immediate circulation to the wellbore.

The kill fluid shall provide for a minimum 1,500 kPa overbalance when spotted.

Degradation of the kill fluid (gel strength if weighting material is required), lost circulation issues, and the effects of winter operations shall be taken into account when managing the kill fluid system.

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

For wells that can be shut-in, contingency plans shall be in place for a back-up pump with manifold to be brought to location should the fluid pump fail.

WEIGHTING OR LOST CIRCULATION MATERIAL

If weighting or lost circulation material (LCM) is required to kill the well, consideration should be given to the ability to successfully circulate these materials through the BHA.

Circulating subs above flow restrictions may be necessary.

4.3.3 CORROSION AND EROSION

Corrosion is the destruction of metal by chemical or electrochemical means. Potential agents for initiating corrosion include carbon dioxide, hydrogen sulphide, chlorides, and oxygen. All of these 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.

Erosion is 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.

Steps shall be taken to minimize the corrosive potential of the circulating media and produced fluids when corrosive conditions exist. These can include the following:

- minimizing/eliminating oxygen, carbon dioxide, hydrogen sulphide, and chlorides in the injection stream;
- adding scavengers and/or inhibitors into the injection stream; or
- the use of corrosive resistant materials.

The effectiveness of corrosion control steps shall be established before starting underbalanced drilling operations.
4.3.4 Monitoring

H₂S Monitoring
Recommendations for H₂S monitoring have been discussed in Section 1.10 of IRP 1: Critical Sour Drilling and Section 2.12 of IRP 2: Completing and Servicing Critical Sour Wells. These references deal with general requirements, equipment, communications and more, and together with regulatory requirements, such as outlined in occupational health and safety regulations, shall be followed.

Oxygen Monitoring
The oxygen content of any injection stream that has the potential to introduce oxygen into the circulating stream shall be monitored to ensure that explosive limits are never reached during underbalanced drilling operations.

Continuous read-out monitors are required and calibration reports shall be available on site.

Flow Rate Monitoring
Circulation parameters shall be monitored to ensure that the system capabilities are not exceeded. Parameters that require monitoring include, but are not limited to, the following:

- gas and liquid production rates,
- injection pressures,
- wellhead annular pressure,
- bottomhole annular pressure, and
- surface volumes.

Corrosion Monitoring
A corrosion monitoring program shall be in place and be appropriate for the corrosion risks of the fluid being used.

During drilling under corrosive conditions, the circulating media shall be monitored to provide for an indication of corrosion and to determine the effectiveness of corrosion control measures being used.

Corrosion indicators (rings, coupons, or suitable alternatives) shall be installed at appropriate/practical circulating stream locations (surface piping, drill pipe, BHA, etc.) to measure corrosion rates if operating under potentially corrosive conditions.

Corrosion indicators shall be regularly inspected to establish corrosion rates.
Consideration should be given to taking precautionary steps such as regularly tripping to inspect the CT string/BHA to establish the severity of downhole corrosive conditions when drilling in an area where the corrosive environment is not thoroughly understood. Each trip will add fatigue to the CT string and this shall also be considered.

**EROSION MONITORING**

- Surface equipment exposed to high pressures or high flow velocities shall be inspected on a regular basis using industry accepted practices to monitor for materials erosion.

**4.3.5 FLUIDS HANDLING, STORAGE, AND TRUCKING**

- Operators shall have site-specific plans in place for collection, transportation, and disposal of hazardous fluids or gases.

**FLUIDS HANDLING SYSTEM**

- Circulated liquids shall be contained in a closed-loop system, unless H₂S levels can be reduced to meet occupational exposure limits, which would then allow the use of open tanks.

**ON-SITE STORAGE CAPACITY**

- Sufficient storage capacity shall be available to temporarily store produced fluids during drilling operations.
- Flush production shall be considered in determining storage requirements.
- Alternatively, provisions for fluid injection or off-site fluids transport shall be in place if on-site facilities do not have the capacity to handle the necessary volumes.
- Consideration should be given to providing excess storage capacity in the event of unforeseen circumstances, such as inclement weather conditions, which may compromise proper fluid handling abilities.
- Sour fluid volumes stored on location should be minimized for added safety of on-site personnel.

**FLUIDS TRANSPORT**

- Spill contingency plans for storage, loading, unloading, and transporting fluids shall be included in the operator’s site-specific ERP. Refer to [Section 1.6: Preparing Emergency Response Plan (ERP)] of this IRP for further emergency response planning requirements.
Recommendations on Fluids and Circulating Systems

Refer to existing industry documents (e.g. IRP 4: Well Testing and Fluid Handling) and regulatory requirements regarding the transportation of hazardous fluids.

WASTE TREATMENT/DISPOSAL

▶ A waste management plan for produced liquids and drilled solids shall be developed before starting underbalanced drilling operations.

▷ This plan should consider the volume of solids that will be generated and their residual oil, chloride, and H2S content.

▷ If a third party waste handler will be used for disposal, they should be contacted in advance to determine their sour fluids and sour solids handling capabilities.

4.3.6 Equipment

EMERGENCY SHUTDOWN VALVE (ESD)

▶ The working pressure of the ESD components shall be equal to or greater than the anticipated SITHP.

▷ The ESD should be installed as close to the BOP stack as possible to minimize the potential of failure between the stack and the ESD.

▷ A valve position indicator is recommended, equipped with a visual and audible alarm system to be actuated when the ESD is in the closed position.

*Caution: Closing the ESD with an incompressible fluid under high pressure may cause instantaneous pressure spikes.

PRIMARY FLOWLINE

▶ The primary flowline installed between the ESD and the choke manifold must be as straight as possible to minimize friction and erosion.

▷ A uniform piping inside diameter should be maintained to minimize turbulence within the flowline.

Butt weld unions and flanges also help to minimize turbulence.

▷ Appropriate ports should be installed for chemical injection.

▷ Consideration should be given to the installation of a secondary flowline, connected to the manifold and separator.

Pressure Rating

▶ The primary flowline downstream of the ESD to the first control valve must have a working pressure rating equal to or greater than the anticipated...
Internal Diameters

- The primary flowline components between the flow diverter and the separator, with the exception of the choke manifold, shall not have an internal diameter of diminishing size.

- Preferably, the inside diameter of the downstream piping from the choke manifold should be larger than the upstream piping.

Erosion Calculations

- Erosion calculations are required to determine proper flowline sizing, taking into account abrasion, corrosion (cushion tees), slug flow (line jacking), liquid/gas velocities, and solids loading.

Inspection and Certification

- Third party pre-job inspections shall include a thickness inspection and a hydrostatic pressure test.

- The pressure test shall be equal to 1.5 times the working pressure rating of the piping.

- Mill documentation of the piping metallurgy shall be available at the wellsite.

Wellsite Testing and Certification

- The flowline downstream of the BOP stack to the first control valve shall be as follows:
  - hydrostatically pressure-tested for a minimum of 10 minutes to a low pressure of 1,400 kPa and to the anticipated SITHP, and
  - tested with an inert gas medium for a minimum of 10 minutes if the circulating medium is a gaseous fluid or the wellbore effluent is expected to contain free gas to a low pressure of 1,400 kPa and to a pressure equal to 90% of the anticipated SITHP.

Refer to IRP 6: Critical Sour Underbalanced Drilling, Section 6.2 for well control equipment pressure test requirements.

- Pressure testing of the flowline piping shall conform to the following:
  - regulatory requirements of the local jurisdiction (such as the ERCB Oil and Gas Regulation 8.141), and
  - the pressure testing criteria set out in IRP 4: Well Testing and Fluid Handling.

Wellsite Inspection

- Piping shall be thickness-tested (ultrasonically) at predetermined erosion
spots, to determine loss of piping thickness.

- Records of the inspection shall be kept at the wellsite.
- The inspection frequency shall be increased if wear becomes noticeable.
- High rate gas wells shall be monitored on a continuous basis.

The intent of this inspection is to ensure that wear spots are identified prior to pipe failure. Refer to IRP 6: Critical Sour Underbalanced Drilling for operability recommendations, which include erosion calculations.

**CHOKE MANIFOLD**

- The choke manifold must have a pressure rating equal to or greater than the anticipated SITHP, and shall include the following components:
  - two chokes, and
  - isolation valves for each choke and flow path.
- All components within the choke manifold must conform to NACE MR-01-75 specifications.

**DOWNSTREAM INLET PIPING**

- All piping downstream of the choke manifold up to and including the separator inlet must conform to NACE MR-01-75 specifications and have a working pressure equal to or greater than the design operating pressure of the separator.

**SAMPLE CATCHER**

- Before geological sample recovery, the sample catcher shall be purged with either an inert gas or a sweet gas.
- The sample recovery procedure shall still be considered sour and personnel shall take precautions accordingly.
- The purged sour gas shall be vented into the vapour recovery system.

**INJECTION LINE BLEED-OFF**

- The injection line bleed-off components must comply with NACE MR-01-75 specifications and have a working pressure equal to or greater than the anticipated SITHP.
**SEPARATOR**

- Separator equipment components that will come into contact with sour gas must comply with *NACE MR-01-75* specifications.

- The separator must be certified by applicable provincial regulatory bodies supporting compliance to pressure vessel and electrical standards.

- At the wellsite, current documentation shall be available that verifies the function testing of the pressure relief valves.

- Assurance of correct sizing of the pressure relief valves shall be supported with gas flow calculations available at the wellsite.

- The separator equipment capacity should be determined by considering the hole size, depth, reservoir pressure, anticipated flow rates, H2S concentration, and expected solids recovery.

**FLUIDS HANDLING**

- All fluids handling equipment, except storage tanks, must conform to *NACE MR-01-75* specifications.

- The fluids handling system and the separator capacity should be based upon maximum potential production at maximum drawdown. (In a prolific gas reservoir this may not be possible, in which case an adequate manifold system for holding back pressure would be mandatory).

- Short-term near-wellbore flush production can result in flow rates that can significantly exceed expected rates. If the well to be drilled is in an area with little production experience or is a significant step location, the fluids handling system and the separator size should be selected to provide for excess capacity.

- For the drilling of a sour gas reservoir where the potential exists for production rates larger than the sizing of the separator vessel and at a relatively high flowing wellhead pressure, a high pressure separator should be used, or as a minimum a second manifold (installed in series no closer than 10 pipe IDs from the previous manifold) should be considered to step down any potential large surface circulating pressures (instead of using one manifold and taking the entire pressure drop across a single system). Chokes that are highly erosion-resistant should be used.

The reason for these recommendations is to minimize the degree of pressure drop across one restriction, thereby minimizing erosion. In an oil well, these steps may not be warranted if the anticipated bottomhole pressures would not cause high flowing wellhead pressures. In this case, an industry-accepted manifold and separation vessel would be sufficient.

*NACE MR-01-75* specifications do not apply to storage tanks, since fluids are stored
below 350 kPa.

► Refer to the regulatory requirements of the local jurisdiction for additional sour fluids requirements. In Alberta, or in the absence of any local jurisdictional requirements, consult ERCB Interim Directive ID 94-3.

► IRP 22: Underbalanced and Managed Pressure Drilling Operations Using Jointed Pipe may give further useful information on fluids handling.

PUMP LINES

► Pump lines and related components used for pumping fluid down the coiled tubing shall have a working pressure rating that would allow the well to be killed. Therefore, the pressure rating shall be equal to or greater than the friction pressure of the fluid being pumped down the coil plus the anticipated SITHP.

► Elastomers shall be compatible with the fluid circulating medium and the service conditions.

► Pump line equipment shall also include two check valves (with bleed-off line between them) installed between the pump and coiled tubing reel, and have a working pressure equal to or greater than the anticipated SITHP.

► A pressure relief valve adequately sized for the pump rates anticipated is also required.

4.4 USE OF AIR

► In cases of inconsistency between the recommended practices on the use of air contained in this IRP and applicable legislation, the legislative requirements prevail.

► Pumping of air is allowed only on a well meeting the following criteria:
  • the reservoir pressure of the zone is less than 5,500 kPa,
  • there is no hydrogen sulphide present in a representative sample of the gas, and
  • the well is a gas well or the well produces heavy oil with a density greater than 920 kg/m³, a gas-oil ratio of less than 70 sm³/m³, and the well produces by primary recovery or is included in a water-flood scheme.

Air can be used when drilling through non-hydrocarbon bearing zones. For further information on the use of air in Drilling Operations consult the pending IRP 22: Underbalanced and Managed Pressure Drilling Operations Using Jointed Pipe, Sections 22.3.10 Unplanned Oil/Condensate Production, and 22.3.15 Air Drilling Operations.

► Air shall not be used on any well containing H₂S.
Further information can be found in Section 4.3.5.2 of IRP 4: Well Testing and Fluid Handling.

- If the well contains any liquids, consult local jurisdictional requirements. In Alberta, or in the absence of any local jurisdictional requirements, consult ERCB Safety Bulletin 2003-02.

- Before starting operations, an assessment of the operations shall be done using the tools and methods outlined in IRP 18: Fire and Explosion Hazard Management.

- In addition, the latest release of ERCB Directive 033: Well Servicing and Completions Operations - Interim Requirement Regarding the Potential for Explosive Mixtures and Ignition in Wells should be consulted, and when gases are to be vented, consult ERCB Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting Section 8.1 (or other jurisdictional legislation).

- Issues pertinent to CT operations that shall be considered in this assessment include, but are not limited to the following:
  - well pressure,
  - pumping pressure,
  - depth,
  - flammable liquids in wellbore,
  - ignition sources,
  - presence or absence of water, and
  - purge of wellbore after operation.

- Air can be flowed back only to an open tank.

- With the coiled tubing in the well, pressure shall not be bled back through the coil if pumping air and the BHA does not contain a barrier (check valve, etc.).
Section 5 Recommendations on Quality Assurance for Well-Pressure-Containing Equipment

This section addresses the following topics:

1. requirement for a quality assurance program,
2. manufacturing of API and non-API well-pressure-containing equipment,
3. shop servicing and repairs, and
4. quality control of non-API well-pressure-containing equipment.

The recommended practices for a quality assurance program for well-pressure-containing equipment listed below have been summarized from IRP 2: Completing and Servicing Critical Sour Wells, and recognize the need to ensure that the well pressure control or pressure-containing equipment used is suitable for its intended service.

Users are reminded to check for updates and follow the latest specifications. Well operators and service providers are responsible for ensuring that any well-pressure-containing equipment conforms to regulatory requirements and the recommended and best practices in this and other IRPs.

5.1 Requirement for a Quality Assurance Program

A suitable quality assurance program should be implemented, in particular for well-pressure-containing equipment not manufactured in compliance with an applicable API specification and API Spec Q1: Quality Program 1.

Well pressure control equipment used for critical sour well completion, servicing and drilling operations shall be manufactured and maintained under a quality assurance program to ensure conformance with design specifications including suitability for sour service.

5.2 Manufacturing of API Well-Pressure-Containing Equipment

Well-pressure-containing equipment used in critical sour wells made to API specifications must be manufactured by an API-licensed manufacturer.

The equipment must 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.
Technical quality requirements that are beyond the scope or exceed the technical/quality requirements of the applicable API specification must be per manufacturer’s written procedures.

API Spec Q1: Specification for Quality Programs and ISO 9001 detail all aspects of quality assurance programs.

5.3 MANUFACTURING OF NON-API WELL-PRESSURE-CONTAINING EQUIPMENT

Well-pressure-containing equipment used in critical sour wells not requiring compliance to API specifications shall be manufactured by a company that has a quality assurance program that addresses the following areas:

- procurement control and traceability,
- incoming inspection,
- calibration of measurement and testing equipment,
- quality records,
- personnel qualifications,
- inspection plan,
- manufacturer’s mark,
- size and rated working pressure, and
- handling, storage, and shipping procedures.

Well-pressure-containing equipment used in critical sour wells not requiring compliance to API specifications shall be identified as such in accordance with manufacturer’s written procedures.

5.4 SHOP SERVICING AND REPAIRS

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

Shop servicing and repairs shall be done by either an API-licensed manufacturer or a company that meets the requirements in Section 5.3: Manufacturing of Non-API Well-Pressure-Containing Equipment above.

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

5.5 QUALITY CONTROL OF NON-API WELL-PRESSURE-CONTAINING EQUIPMENT

5.5.1 MINIMUM QUALITY CONTROL MEASURES
The minimum quality control measures set out in Table 9 below shall be used to ensure the well-pressure-containing equipment is suitable for critical sour well operations.

Table 9: Minimum Quality Control Measures and Methods

<table>
<thead>
<tr>
<th>Minimum Quality Control Measures for Non-API Well-Pressure-Containing Equipment</th>
<th>Method</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mechanical tests</td>
<td>Tests commonly run are tensile, hardness.</td>
</tr>
<tr>
<td>Non-destructive examination</td>
<td>Commonly used methods are ultrasonics, magnetic particle, dye penetration, visual.</td>
</tr>
<tr>
<td>Dimensional verification</td>
<td>Shall be in conformance with design specifications.</td>
</tr>
<tr>
<td>Chemistry verification</td>
<td>Shall be in conformance with design specifications.</td>
</tr>
<tr>
<td>Traceability to end user</td>
<td>Traceability of component from raw material through manufacturing processes to end user.</td>
</tr>
<tr>
<td>Wellsite traceability</td>
<td>Component(s) shall be marked in such a fashion so that on-site personnel can verify that the component delivered to the wellsite is suitable for sour service.</td>
</tr>
</tbody>
</table>

NOTE: Other tests may be required for special applications (e.g. Charpy impact testing for low temperature notch toughness).

5.5.2 Destructive and Non-Destructive Testing Methods

Tables 10 and 11) below list destructive and non-destructive methods for the evaluation of materials for critical sour well operations.
<table>
<thead>
<tr>
<th>Type of Non-Destructive Testing</th>
<th>Related Standards</th>
<th>Use for Testing</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chemical analysis</td>
<td>ASTM E751-04</td>
<td>Used to establish the hardenability of the material and the likelihood of having hard-heat-affected weld zones which would be susceptible to SCC. Used to determine the material type and its conformance to Tables I, II, and III of NACE MR0175, latest edition. Used to confirm compliance with the 1% Nickel content restriction of NACE MR0175, latest edition.</td>
</tr>
<tr>
<td>Eddy current inspection</td>
<td>ASME Section V, ASTM E309-95</td>
<td>Used to detect cracks and volumetric defects in tubular products, although variations in test equipment do allow for the inspection of other types of components.</td>
</tr>
<tr>
<td>Hardness testing</td>
<td>ASTM E10-01, E18-02</td>
<td>Used to confirm compliance with the hardness restrictions of NACE MR-01-75, latest edition.</td>
</tr>
<tr>
<td>Liquid penetrant inspection</td>
<td>ASME Section V, ASTM E165-95</td>
<td>Used to detect surface defects on non-magnetic components, although it can be used for magnetic components. Several types are available with widely varying sensitivities—for the detection of SCC (sulphide corrosion cracking), one of the more sensitive methods should be used.</td>
</tr>
<tr>
<td>Magnetic particle inspection</td>
<td>ASME Section V, ASTM E709-01</td>
<td>Used to detect surface defects and near surface linear discontinuities in magnetic components. For small fine cracking such as SCC, wet fluorescent techniques should be used.</td>
</tr>
<tr>
<td>Radiography</td>
<td>ASME Section V, ASTM E1030-00, E1032-01, E94-00</td>
<td>Used to evaluate welds and castings for volumetric defects.</td>
</tr>
<tr>
<td>Ultrasonic inspection</td>
<td>ASME Section V</td>
<td>Used to evaluate welds and castings for volumetric defects and linear discontinuities (cracks).</td>
</tr>
</tbody>
</table>
### Table 11: Destructive Testing for Evaluating Materials for Critical Sour Operations

<table>
<thead>
<tr>
<th>Type of Destructive Testing</th>
<th>Related Standard</th>
<th>Use for Testing</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bend testing</td>
<td>ASTM A370-01</td>
<td>Used to measure a weld’s or material’s ability to deform under load without cracking or suddenly failing (usually used for weld procedure and welder qualification testing).</td>
</tr>
<tr>
<td>Impact testing</td>
<td>ASTM A370-01</td>
<td>Used to establish a relative measure of the material’s or weld’s resistance to fracture at low temperatures under high and suddenly applied loads.</td>
</tr>
<tr>
<td>Tensile testing</td>
<td>ASTM A370-01</td>
<td>Used to establish the yield and tensile strength of a material or weld as well as its ductility and whether it complies with the minimum specified values for that particular grade.</td>
</tr>
</tbody>
</table>
Section 6 RECOMMENDATIONS ON ELASTOMERIC SEALS

This section addresses the following topics regarding elastomeric seals:

1. service conditions,
2. testing and evaluation,
3. quality control, and
4. supporting information.

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

This section should help well operators select elastomers for well pressure seals. However, plastic seals (such as Teflon and Ryton) and metal-to-metal seals (such as flange gaskets) are often preferred because of their greater resistance to attack by produced or injected fluids. Note that seal design as well as plastic and metal-to-metal seals are outside the scope of this IRP; consult manufacturers.

Further details on the requirements for elastomeric seals in critical sour underbalanced drilling can be found in IRP 6: Critical Sour Underbalanced Drilling, Section 6.2.4.

6.1 SERVICE CONDITIONS

- Compatibility of any elastomeric seal with the intended service environment shall be determined when selecting materials and equipment for the completion, servicing, or drilling of a critical sour well.

- This 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.

APPENDIX C provides a basic reference for elastomer selection.

- Manufacturer-supplied performance properties and recommendations should also be used.

6.2 TESTING AND EVALUATION

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

- To evaluate the suitability of elastomers and other seal materials for a particular well, the user should first refer to the equipment manufacturer’s recommendations. These recommendations should be based on materials testing and experience.

- In addition, the end user shall be satisfied that information or data on seal materials meet the intended service requirements.

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

### 6.3 QUALITY CONTROL

- The well operator shall ensure that records identifying the elastomer materials in use for first-line well pressure control seals are kept. The first-line well pressure control seals include equipment such as BOP elements and lubricator O-rings. Keeping these records is recommended because there are no standard markings on most elastomer seals to indicate the elastomer material.

### 6.4 SUPPORTING INFORMATION

#### 6.4.1 SEAL DESIGN

Sealing materials normally include elastomers or elastomers with plastics. 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.

Plastics, such as Teflon, Ryton, or PEEK, are polymers that are stronger and have better chemical resistance than elastomers but do not have the resilience (rebound) properties of elastomers. Plastics are normally used in conjunction with elastomers for anti-extrusion back-up.

There are many different elastomeric and plastic seal configurations available for well servicing and completion equipment. O-ring, V-ring, bonded seals, and compression-force-activated seals are some of the more common seal configurations.

- Seal design is generally done by the equipment manufacturer. However, end users should familiarize themselves with seal designs available and determine the compatibility for the intended service between the seal material and the seal design. The following factors should be considered:
  - seal movement—differences between static and dynamic seals should be taken into consideration in the design;
  - service period—the length of service should be considered when selecting seal materials as seal material will often perform satisfactorily for a short service period but would be unsuitable for extended service...
• 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 on longer-term changes, which may occur in the well’s produced fluids such as increasing H₂S or temperature. Also, initiation of secondary or tertiary recovery could have effects on sealing materials.

6.4.2 Service Conditions

Users should be aware of the various fluids to be handled and their individual or combined effect on sealing materials. These fluids include the anticipated well production fluids and any other fluid encountered during workovers or any chemical additives introduced to the well.

Appendix C provides an outline of some of the more common oilfield elastomers, including typical properties. Users should also be aware that for a given generic type of elastomer (e.g. nitrile), manufacturers may have different formulations or compounds each with different chemical resistance and temperature ratings.

6.4.3 Seal Material Selection

With regard to seal material selection, two important parameters are temperature (service and ambient) and the fluids to be encountered for the intended application. Pressure will affect seal mechanical design and operating parameters more than it affects the seal material. Rapid depressurization of the system can also cause rupture of the seal material (explosive decompression).

Temperature

Elastomers and plastics have upper and lower temperature limitations that are usually published by the seal manufacturer and are available through them or the equipment supplier.

The general chemical resistance of elastomers at low temperatures may be critical for BOPs or other equipment. Supplementary heating could be required for the BOP element based on equipment manufacturer’s guidelines or government regulations.

The T5 temperature measured by the ASTM D1053 test or the TR10 plus 5°C temperature measured by the ASTM D1329 test can be used as estimates of a minimum operating temperature for an elastomer. The Glass Transition Temperature (Tg) of the elastomer is also used to help determine the low temperature capability.
FLUIDS

Fluid exposures can cause changes in the seal material. Some of these changes are reversible and others are not. For example, the seal swelling caused by gas or oil permeation may reverse itself once the elastomer is removed from the exposure environment. H₂S exposure to elastomers can cause additional cross-linking of the elastomer to occur, which results in embrittlement. This change is irreversible.

The aromatic component of mineral-oil-based fluids that can be present in crude oil, invert emulsion muds, and frac oil can swell and weaken some elastomers. Alcohol, such as methanol, causes some elastomers to lose their resilience. Amine-based corrosion inhibitors and sulphur solvent chemicals such as dimethyl disulphide (DMDS) are very aggressive to many elastomers. Negative effects of these chemicals can vary depending on the elastomer, service, and concentration of chemicals. This effect may be difficult to predict and may require specific testing to determine adverse effects.

6.4.4 TESTING AND EVALUATION

No oilfield industry testing and evaluation standard exists for elastomers used in oilfield equipment and so the manufacturer’s standards are often used. However, API does have specific test requirements for verifying elastomer performance for wellhead and drill-through equipment. These tests are based on standard test environments and equipment temperature and pressure ratings.


6.4.5 QUALITY CONTROL FOR ELASTOMERS

Storage and handling should also be included in the quality control program because many elastomers have a shelf life due to sensitivity to sunlight and humidity. Inventory control is especially important because most elastomers look alike. Even in the same generic category such as nitrile, small chemical and dimensional variances made by manufacturers will drastically change the elastomer effectiveness for the given application.

API and ISO are recommended sources of further quality control information on elastomers.
Section 7 Recommendations on Coiled Tubing Operations for Well Servicing

This section addresses the following topics regarding CT operations for well servicing:

1. pre-rig-up recommendations,
2. rig-up recommendations,
3. pressure tests,
4. equipment records,
5. operating practices, and
6. recommendations on BHAs.

7.1 Pre-Rig-Up Recommendations

Before rigging up any coiled tubing equipment on the location, the operating company and service company shall review the equipment service log and ensure the following:

1. the coiled tubing pipe to be used shall have sufficient serviceability to safely complete the job with a reasonable contingency factor;
2. the coiled tubing string used shall be able to complete the job within operating limits (such as tensile strength, burst, collapse, torsional yield, etc.);
3. the three-year BOP equipment certification must have been completed (this includes all riser, lubricator, flow spools, cross-overs, strippers, etc., from the wellhead to the upper stripper);
4. the accumulator specifications must be available and accumulator sizing calculations must have been performed;
5. all equipment, including the coiled tubing pipe and BOP system, shall have been checked for compatibility with the formation fluids and treating fluids;
6. if the shear ram is installed, it shall be capable of severing the coiled tubing pipe and any internal/external hardware such as wireline-installed coiled tubing being used;
7. for cold weather operations consideration must be 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 pipe, refer to Section 3.6.2: Full-Length NDE of CT Strings of this 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 (such as rat holes, high pressure piping, etc.),
  - muster stations, and
  - egress routes.

- The operating company and service company shall review the well parameters including, but not limited to the following:
  - asphaltenes,
  - condensate,
  - depth,
  - formation or treatment fluids,
  - gas composition (especially air, H₂S, and CO₂ concentrations),
  - hydrate formation,
  - emergency response plan (ERP) if required,
  - iron sulphide,
  - naturally occurring radioactive material (NORM),
  - other scales,
  - pressures,
  - relevant well equipment and detail (trajectory, ID restrictions, etc.),
  - salinity of produced water,
  - sulphur scales,
  - wax, and
  - wind direction.

- The operating company and service company shall review proposed equipment layout and spacing requirements recognizing all regulatory requirements.

When running velocity strings consideration should be given to the inclusion of a landing nipple at the bottom of the string. An isolation dart can then be landed prior to pulling the string that will minimize the possibility of a release should the string part above the well control equipment on recovery. This is strongly recommended on sour wells.
7.2 **Rig-Up Recommendations**

- A safety/operations meeting shall be held with all on-location personnel to discuss the following:
  - pressure testing,
  - the detailed operations to be performed,
  - delegation of responsibilities,
  - review BOP Drill requirements,
  - emergency response plans, and
  - other appropriate considerations.

- 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.

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

Refer to **Section 1: Recommendations on Coiled Tubing Operations Planning** of this IRP for detailed matters to be addressed during the safety/operations meeting.

- Injector height, equipment weight, and wind conditions should be considered.

- Guy lines should be installed to rig anchors or a secure anchor point as deemed necessary.

- If liquid CO2 is to be pumped, contingency plans shall be in place to deal with ice plugs in the surface piping (treating iron, coiled tubing, etc.).

7.3 **Pressure Tests (PT)**

- With the coiled tubing BOP components and auxiliary equipment installed on the wellhead, the BOP system shall be pressure tested as follows:
  - A low-pressure test of 1,400 kPa must be conducted on each ram preventer for ten minutes. This test is to be conducted first.
  - A high-pressure test must be conducted on each ram preventer for ten minutes. The pressure required shall be the wellhead pressure rating or 1.1 times the estimated maximum potential SITHP (for critical sour wells 1.3 times the estimated maximum potential SITHP)—whichever is the lesser.
  - The annular preventer must be pressure tested for ten minutes to the wellhead pressure rating or 1.1 times the estimated maximum potential SITHP (for critical sour wells 1.3 times the estimated maximum potential SITHP)—whichever is the lesser.
  - The stuffing box assembly must be pressure tested for ten minutes to the wellhead pressure rating or 1.1 times the estimated maximum potential SITHP (for critical sour wells 1.3 times the estimated maximum potential SITHP)—whichever is the lesser.
An on-location stump test is acceptable if a pressure test of the connecting flange is completed after installation on the well.

A produced hydrocarbon is not an acceptable pressure testing medium.

- The following components of the BOP system shall be pressure tested for ten minutes to the wellhead pressure rating or 1.1 times the estimated maximum potential SITHP (for critical sour wells 1.3 times the estimated maximum potential SITHP)—whichever is the lesser:
  - the connection between the BOP stack and the wellhead,
  - auxiliary equipment including lubricators and pressure windows,
  - bleed-off and kill lines,
  - all valves in the bleed-off manifold (if applicable),
  - reel isolation valve,
  - rotary swivel (pressure tested to the criteria above or maximum anticipated wellhead treatment pressure—whichever is greater),
  - coiled tubing pipe (pressure tested to the criteria above or maximum anticipated wellhead treatment pressure—whichever is greater), and
  - downhole equipment composing a part of the coiled tubing pipe above the isolation device (check valves).

Adjustable chokes do not require testing.

- A differential pressure across the check valve shall be established to confirm check valve integrity before running in the hole.

- For a satisfactory pressure test using a liquid, all tests shall maintain a stabilized pressure of at least 90% of the test pressure over a 10 minute interval.

- For a satisfactory pressure test using an inert gas or air, not more than 5% of the value of the test pressure is to be recorded to have leaked off during the test period. If more than 5% has leaked off, then the length of the test shall be increased to determine the nature of the pressure decline.

- Where well classification or the greater of reservoir pressure and SITHP is not clear through past operations, pressure tests should be conducted to the wellhead pressure rating.

For Alberta Class I operations, a daily pressure test is acceptable.

- If air is to be used as a test medium, all regulatory requirements must be met and the appropriate hazard assessments carried out.

### 7.4 Equipment Records

Equipment records are records detailing information about the history of the equipment used during CT operations.
- 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.

Records should be kept of the following:
- all operations conducted with the coiled tubing pipe being used,
- fluid types and/or gases pumped, and
- metres run and cycled.

See Sections 3.9.4: CT String Post-Production Records and 3.11: Implementing a CT String-Life Management System of this IRP for further details.

### 7.5 OPERATING PRACTICES

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

- 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.

- While in the hole, coiled tubing pipe shall not exceed operating limits.

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.

In the event of a serious wellhead leak between the coiled tubing BOP stack and the master valve, consideration should be given to the following procedure in order to bring the well under control:

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.

For Class II and III wells, if the procedures listed above cannot be performed, consideration should be given to the following procedure:

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.

- 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. Stress risers will make the coiled string significantly more susceptible to failure in sour gas environments. This applies to the BOP Drill only, in emergency situations the slip rams should be closed if the situation merits it.

### 7.6 RECOMMENDATIONS ON BHAs

#### 7.6.1 Sour Conditions

- When working in sour conditions (see glossary for definition), all parts of the BHA from the end connector down to the check valves should meet the requirements of NACE MR0175.

- All load bearing parts of the BHA should meet NACE MR0175.

#### 7.6.2 Critical Sour / Special Sour Wells

- All parts of the BHA from the end connector down to the check valves shall meet the requirements of *NACE MR0175*.

- All load bearing parts of the BHA should meet NACE MR0175.
Section 8 Recommendations on Coiled Tubing Operations for Drilling

This section addresses the following topics regarding CT operations for drilling:

1. general requirements,
2. underbalanced drilling,
3. critical sour underbalanced drilling,
4. rig-up recommendations,
5. pressure tests,
6. operating practices, and
7. recommendations on BHAs.

8.1 General Requirements

8.1.1 Service Log

The operating company and service company shall review the equipment service log and ensure the following:

- the coiled tubing drill string to be used has sufficient serviceability to safely complete the job with a reasonable contingency factor,
- the three-year BOP equipment certification has been completed (this includes all equipment from the bottom of the BOP to the top of the wellhead),
- the accumulator specifications are available and accumulator sizing calculations have been performed and documented,
- the well control equipment conforms with the applicable well classification as per jurisdictional requirements,
- all equipment including the coiled tubing drill string and BOP system are checked for compatibility with the formation fluids and treating fluids,
- if installed, a shear ram BOP is capable of severing the coiled tubing drill string and any internal or external hardware such as wireline-installed coiled tubing, and
- for cold weather operations consideration must be given to heating (or other appropriate actions) of the BOPs to ensure that the response time
and sealing efficiency is satisfactory.

8.1.2 ORIENTATION OF SERVICE COMPANY REPRESENTATIVE

- The operating company representative shall provide 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 (such as rat holes, high pressure piping, etc.),
  - muster stations, and
  - egress routes.

- The operating company and service company shall review the well parameters including, but not limited to, the following:
  - asphaltenes,
  - condensate,
  - depth,
  - formation and drilling fluids,
  - gas composition (especially air, H₂S, and CO₂ concentrations),
  - hydrate formation,
  - emergency response plan (ERP) if required,
  - iron sulphide,
  - naturally occurring radioactive material (NORM),
  - other scales,
  - pressures,
  - relevant well equipment and detail (trajectory, ID restrictions, etc.),
  - salinity of produced water,
  - sulphur scales,
  - wax, and
  - wind direction.

8.1.3 EQUIPMENT LAYOUT AND SPACING REQUIREMENTS

- The operating company and service company shall review proposed equipment layout and spacing requirements, recognizing all regulatory requirements.

8.1.4 COILED TUBING MECHANICAL PROPERTIES

- The coiled tubing drill string used shall be able to complete the job within operating limits (such as tensile strength, burst, collapse, torsional yield, etc.).
8.1.5 **INHIBITORS**

- Inhibitors shall be present in sufficient quantities to protect the exposed materials (such as coiled tubing drill string, downhole equipment, etc.) during operations where the coiled tubing drill string is exposed to a corrosive media.

- Consideration shall be given to the total circulation system (e.g. the presence of water, salinity, oxygen content, H₂S, CO₂, and temperature).

8.2 **UNDERBALANCED DRILLING**

8.2.1 **PRESSURE LIMITS**

- For underbalanced drilling operations, coiled tubing drill string differential pressure limits shall be established for each operation. These limits shall take into account the following:
  - tube diameter,
  - ovality,
  - wall thickness,
  - applied loads, and
  - the anticipated operating conditions.

8.2.2 **FATIGUE CYCLES**

- For underbalanced drilling operations, fatigue cycles remaining in the coiled tubing drill string at the anticipated circulating pressures, and at 25% above the anticipated circulating pressures or the maximum operating pressure (whichever is less) shall be posted in the coiled tubing operating unit.

Specifying fatigue cycles remaining at 25% above the anticipated circulating pressure accounts for situations where the circulating pressure is higher than predicted (due to higher than anticipated reservoir pressures or flow rates).

8.2.3 **SWIVEL ISOLATION VALVE**

- A valve between the coiled tubing drill string and the reel swivel is required on all underbalanced wells.

8.3 **CRITICAL SOUR UNDERBALANCED DRILLING**

8.3.1 **TORSIONAL YIELD**

- The torsional rating of the coiled tubing drill string shall be greater than two times the downhole motor stall torque.

- The torsional rating of the coiled tubing drill string BHA, including any connectors, shall be their original specification less 20% for all critical sour
underbalanced drilling. This rating shall be greater than 1.5 times the downhole motor stall torque.

- The coiled tubing owner shall carry out such tests as are deemed appropriate by the coiled tubing owner to prove the fitness for purpose for sour service of the coiled tubing drill string connector system. The connector system comprises all of the items carrying loads from the BHA to the coiled tubing drill string and the condition of the coiled tubing drill string at the interface with the connector.

These precautions are meant to ensure that neither the pipe nor the BHA/connector twists off under stall conditions. Unless information exists to the contrary, it should be assumed that the motor stall torque is twice the maximum operating torque.

### 8.3.2 Stress Analysis

- Technical personnel competent in tubing force and circulation analysis shall be on location during all coiled tubing drill string critical sour underbalanced drilling operations.

- Coiled tubing drill string stress analysis (including drag predictions) shall be completed before starting critical sour underbalanced drilling operations.

- Coiled tubing drill string design shall take into account appropriate factors such as desired overpull, drag, and wellbore profile.

- For critical sour underbalanced drilling operations, operating limits shall be established and clearly posted in the coiled tubing drill string operating unit for the following:
  - maximum coiled tubing drill string pull weights,
  - set down loads, and
  - circulating pressures.

### 8.3.3 Pipe Inspection

- Pipe inspection of the coiled tubing drill string shall be carried out before use in critical sour underbalanced drilling (refer to Section 3.6: Recommendations on Coiled Tubing Operations Planning of this IRP).

- Inspection results shall be used in conducting tubing force analysis and in calculating circulation limits. As a minimum, coiled tubing drill string OD, minimum wall thickness, and ovality shall be measured.

### 8.3.4 On-Site Documentation

- The coiled tubing operator shall keep records on coiled tubing drill string cycle life, pipe management, and well conditions during critical sour underbalanced drilling operations.
8.4 **Rig-Up Recommendations**

- A safety/operations meeting shall be held with the operators representatives, coiled tubing crew, and all personnel on the lease to discuss the following:
  - pressure testing,
  - the detailed operations to be performed,
  - delegation of responsibilities,
  - review BOP Drill requirements,
  - emergency response plans, and
  - other appropriate considerations.

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

- All equipment attached to the wellhead shall be adequately supported to limit lateral movement.

- Each coiled tubing operation should be evaluated for potential lateral movement of the equipment rigged onto the wellhead.

- Injector height, equipment weight, and wind conditions should be considered.

- Guy lines should be installed to rig anchors or a secure anchor point as deemed necessary.

8.5 **Pressure Tests**

8.5.1 **General Requirements**

- Pressure tests must be carried out as per the applicable jurisdiction.

- For a satisfactory pressure test using a liquid, all tests shall maintain a stabilized pressure of at least 90% of the test pressure over a 10 minute interval.

- For a satisfactory pressure test using an inert gas or air, not more than 5% of the value of the test pressure is to be recorded to have leaked off during the test period. If more than 5% has leaked off then the length of the test shall be increased to determine the nature of the pressure decline.

- In the absence of any specific jurisdictional requirements, ERCB Directive 036: Drilling Blowout Prevention Requirements and Procedures should be consulted.

- Before drilling out intermediate or production casing, the coiled tubing drill string, valves, and piping to the circulating pump shall be pressure tested to the working pressure of the required class of BOPs.

A produced hydrocarbon is not an acceptable pressure testing medium.
In most overbalanced drilling cases, the drilling circulating pressure exceeds the required pressure test requirements and is an acceptable method of pressure testing the coiled tubing drill string.

8.5.2 **UNDERBALANCED DRILLING**

- The coiled tubing drill string shall be pressure tested on all wells above Class I.
- The coiled tubing drill string, valves, and piping to the circulating pump shall be pressure tested to the greater of the maximum anticipated circulating pressure plus 10% or the working pressure of the required class of BOPs.

8.5.3 **CRITICAL SOUR UNDERBALANCED DRILLING**

For further information on the general requirements for critical sour underbalanced drilling, refer to *IRP 6: Critical Sour Underbalanced Drilling*.

**WELLSITE TESTING**

- Pressure testing of the pressure-containing-system (defined below) conducted at the wellsite **must** conform to regulatory requirements. The intent of the pressure test requirements is that the BHA can be pressure-deployed at the highest possible anticipated pressure.
- If the circulating medium is a gaseous fluid or if drilling a critical sour gas well, a gas pressure test with an inert gas shall be conducted in addition to a hydrostatic pressure test of all pressure-containing-equipment.

A pressure containing 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 (e.g. BOP, snubbing, pressure deployment), and specifically the BOP stack, snubbing stack, coiled tubing stack, and pressure deployment system including all bleed lines.

**PRESSURE-CONTAINING-SYSTEM**

- The pressure-containing-system shall be hydrostatically pressure tested for a minimum of ten minutes to a low pressure of 1,400 kPa, and a pressure equal to the maximum potential SITHP.

Maximum potential SITHP (for the purpose of this IRP) is equal to the original reservoir pressure minus the gas gradient, or 85% of the original reservoir pressure. The pressure can be reduced to 85% of the current reservoir pressure if a qualified reservoir specialist endorses a reduction based on factual data.

This requirement reflects the additional rigor required in the planning and design of critical sour underbalanced drilling.
- The pressure-containing-system shall then be pressure tested with an inert
gas if the circulating medium is a gaseous fluid or if the wellbore effluent is expected to contain free gas, for a minimum of ten minutes to a low pressure of 1,400 kPa, and a pressure equal to 90% of the maximum potential SITHP.

► Documentation of the hydrostatic and gas pressure tests shall be kept at the wellsite throughout the duration of the sour underbalanced drilling operation.

► If any connections in the pressure-containing-system are broken during operations, those connections shall be pressure tested again before operations can continue.

► All tests conducted on the annular-type preventers shall be conducted with the element closed on pipe.

Test plugs can be used to isolate the BOP system from the production casing during pressure tests.

Refer to Section 6.5 of IRP 6: Critical Sour Underbalanced Drilling for casing pressure testing requirements.

**COILED TUBING DRILL STRING**

► Before tripping the coiled tubing drill string into the hole, the double check valve in the BHA shall be bench-tested just before being run in the hole, to 1,400 kPa for a minimum of 10 minutes and to 1.1 times the maximum potential SITHP for a minimum of 10 minutes with an inert gas.

► The coiled tubing drill string between the double check valve and the rotating joint on the coiled tubing reel should be pressure tested for a minimum of 10 minutes to 1,400 kPa and the greater of 1.1 times the maximum potential SITHP or maximum anticipated coiled tubing injection pressure.

► The pressure control devices in the BHA during pressure deployment operations into the hole shall be pressure tested from the bottom up using wellbore pressure at surface.

► If the pressure control devices in the BHA do not hold pressure from below during pressure deployment operations into the hole, the coiled tubing drill string shall be pulled from the hole and the existing barriers replaced and pressure tested again before pressure deployment operations into the hole continue.

► If any connections in the coiled tubing drill string between the double check valve and the rotating joint on the coiled tubing reeled unit are broken during operations, those connections shall be pressure tested again as outlined in this section before the coiled tubing drill string can be run back into the well.
8.6 OPERATING PRACTICES

8.6.1 GENERAL REQUIREMENTS

- Before running in the well, the designated senior supervisor on location shall inspect the coiled tubing drill string end connector and document the inspection.

- If the coiled tubing drill string loses the ability to contain pressure, it shall be pulled to surface as soon as it is practical and safe.

- The coiled tubing unit, where the injector head is supported by a crane, shall not be left unattended while the injector head assembly is connected to the wellhead.

- 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. Stress risers will make the coiled string significantly more susceptible to failure in sour gas environments. This applies to the BOP Drill only, in emergency situations the slip rams should be closed if the situation merits it.

8.6.2 UNDERBALANCED DRILLING

- A pull test shall be performed on the coiled tubing drill string to BHA connection before running into the well. The intensity of the pull shall be based on the expected operational requirements.

Pressure testing a blanked end connector is an acceptable alternative to a pull test.

- The well shall be killed in the event of any coiled tubing separation within the wellbore while drilling a critical sour well. String separation is defined as a separation above the highest disconnect in the CT string. This separation may be intentional or as a result of material failure.

- In the event of a serious wellhead leak between the coiled tubing BOP stack and the wellbore isolation valve, consideration should be given to the following procedures in order to bring the well under control:
  1. Ensure everyone on location is safe.
  2. Evaluate if the coiled tubing drill string can be pulled from the well so the wellbore isolation valve can be closed to bring the well under control.
  3. Evaluate if the well can be safely killed and brought under control.

- If the procedures listed above cannot be performed on a well where a shear ram is installed, consideration should be given to the following procedure:
  1. Identify the depth of the bottom portion of the coiled tubing drill string.
2. Pull the bottom of the coiled tubing drill string high enough in the vertical portion of the hole to ensure when the coiled tubing is cut, the top of the coiled tubing drill string will fall below the wellbore isolation valve.

3. Activate the slip rams.

4. Ensure tension is pulled into the coiled tubing drill string above the slip rams, then activate the shear rams and shear the pipe.

5. Open the slip rams and allow the coiled tubing drill string to fall below the wellbore isolation valve.

6. Shut in Wellbore Isolation Valve and secure the well.

8.6.3 **Operation Guidelines**

- For snubbing, stripping, and pressure deployment to be allowed after dark, the lighting at the wellsite shall be sufficient to enable work to be conducted safely, to allow personnel to leave the wellsite safely, to initiate emergency shutdown procedures, and to perform a rescue.

8.7 **Recommendations on BHAs**

8.7.1 **Sour Conditions**

- When working in sour conditions (see glossary for definition), all parts of the BHA from the end connector down to the check valves should meet the requirements of NACE MR0175.

- All load bearing parts of the BHA should meet NACE MR0175.

8.7.2 **Critical Sour / Special Sour Wells**

- All parts of the BHA from the end connector down to the check valves shall meet the requirements of *NACE MR0175*.

- All load bearing parts of the BHA should meet NACE MR0175.
GLOSSARY

NOTE: All terms in this glossary are defined for the purposes of this IRP only.

ADI: automated dimensional inspection.
AEUB: Alberta Energy and Utilities Board; see ERCB.
ASME: American Society of Mechanical Engineers.
BHA: bottom hole assembly.
BOP Drill: A drill to determine the crew’s ability to detect a well kick and to perform a shut in for the operation in progress.
Calibration: comparison and adjustment to a standard of known accuracy.
CAODC: Canadian Association of Oilwell Drilling Contractors.
CAPP: Canadian Association of Petroleum Producers.
Conformance: Compliance with specified requirements.
Critical Lift: a non-routine crane lift requiring detailed planning and additional or unusual safety precautions; all lifts involving an occupied man basket are considered critical lifts; certain jurisdictions may have alternative definitions.
Critical sour well/special sour well (well servicing and drilling): each meets the conditions defined by the applicable provincial regulators; used interchangeably and refer to the current definition from the Alberta ERCB and the current definition by the British Columbia Oil and Gas Commission.
CT: coiled tubing.
CT string-life management system: a manual tracking or computer-based modelling system for predicting the remaining working life of a CT string.
DACC: Drilling and Completions Committee.
Discharge lines: the treatment line from downstream of the discharge of the high pressure pump.
Drilling: consult local jurisdiction regarding the specific definition of drilling operations (in Alberta consult Directive 036: Drilling Blowout Prevention Requirements and Procedures Section 23.1).
ERCB: Energy Resources Conservation Board; formerly AEUB.
ESD: emergency shut down (valve).
Flow Nipple: A non pressure containing device with a side outlet that guides flow back of drilling fluids to the surface mud system. Also referred to as a bell nipple.
Hard shut-in: to close in a well with the BOP having the choke or choke line valve closed.
HAZ: heat-affected zone.
HIC: hydrogen-induced cracking.
Hydrostatic proof-testing of CT strings (non-operational): pressure tests performed on a string of coiled tubing at a facility (manufacturer, end user, or the like); typically
follows any string maintenance being performed on the coil; is separate from any subsequent testing performed during rig-up or other operations at a wellsite.

**IQI:** image quality indication.

**IRP:** Industry Recommended Practice.

**LCM:** lost circulation material.

**Maximum anticipated surface pressure (MASP):** the maximum pressure in the wellbore expected at the wellhead.

**MSDS:** materials safety data sheet.

**NACE:** National Association of Corrosion Engineers.

**NDE:** non-destructive examination.

**NORM:** naturally occurring radioactive material.

**PPE:** personal protective equipment.

**PQR:** procedure qualification record.

**Predicted life to failure:** the fatigue life of a string calculated by a computer model with all safety limits removed.

**Predicted working life:** the fatigue life of a string calculated by a computer model with a known safety factor in place.

**Pressure-containing-system:** the blowout prevention system; includes all equipment from the top wellhead flange to the uppermost piece of pressure control equipment (e.g. BOP, snubbing, pressure deployment), and specifically 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.

**Quality:** Conformance to specified requirements.

**Quality assurance:** planned, systematic, and preventive actions that are required to ensure that materials, products, or services will meet specified requirements.

**Quality control:** inspection, test, or examination to ensure that materials, products, or services conform to specified requirements.

**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; brittle failure by cracking under combined action of tensile stress and corrosion in the presence of water and hydrogen sulphide or chloride.

**Shop Servicing:** a 3 year certification that fulfills the requirements of ERCB Directive 036: Drilling Blowout Prevention Requirements and Procedures, Appendix 5.

**SITHP:** shut-in tubing head pressure.

**Sour conditions:** partial pressure of H₂S in a wet gas phase of the wellbore fluids 0.05 psia (per NACE MR 0175) at MASP.

**Sour service:** partial pressure of H₂S in a wet gas phase of the wellbore fluids 0.05 psia (per NACE MR 0175) at MASP.

**SPE:** Society of Petroleum Engineers.

**SSC:** sulphide stress cracking.

**TDG:** Transportation of Dangerous Goods.
**VME:** Von Mises equivalent.

**Well-pressure-containing equipment:** well completion and servicing equipment that includes but is not limited to wellheads, BOPs, wireline lubricators, tubing, landing nipples and plugs, and downhole packers.

**Well Servicing Class I:** Class I wells meet the following conditions:
- (a) reservoir pressure < 5,500 kPa (798 psi),
- (b) no H₂S in a representative sample of the gas, and
- (c) produced fluid is either of the following:
  - gas, or
  - heavy oil producer with oil density > 920 kg/m³, gas-oil ratio < 70 sm³/m³, and produces by primary recovery or is part of a waterflood.

**Well Servicing Class II:** Class II wells meet either of the following conditions:
- (a) pressure rating of the production casing flange ≤ 21,000 kPa (3,046 psi), or
- (b) H₂S content < 1% by volume.

**Well Servicing Class III:** Class III wells meet either of the following conditions:
- (a) pressure rating of the production casing flange > 21,000 kPa (3,046 psi),
- (b) pressure rating of the production casing flange ≤ 21,000 kPa (3,046 psi), and
- (c) H₂S content ≥ 1% by volume.

**WHMIS:** Workplace Hazardous Materials Information System.

**WPS:** weld procedure specification.
APPENDIX A:

Documents Referred to in This IRP

**ALBERTA ERCB** (Available through [www.ercb.ca](http://www.ercb.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 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting
- Interim Directive ID 94-3
- Oil and Gas Regulation 8.141
- Safety Bulletin 2003-02: Downhole Explosion/Sweet Gas Blowout

**ASTM** (Available through [www.astm.org](http://www.astm.org))

- ASTM A370: [ASTM A370 - 09ae1 Standard Test Methods and Definitions for Mechanical Testing of Steel Products](http://www.astm.org)
- ASTM A370-01: [ASTM A370-01 Standard Test Methods and Definitions for Mechanical Testing of Steel Products](http://www.astm.org)
- ASTM A450: [ASTM A450 / A450M - 09 Standard Specification for General Requirements for Carbon and Low Alloy Steel Tubes](http://www.astm.org)
- ASTM E10-01: [ASTM E10-01 Standard Test Method for Brinell Hardness of Metallic Materials](http://www.astm.org)
- ASTM E1030-05: [ASTM E1030 - 05 Standard Test Method for Radiographic Examination of Metallic Castings](http://www.astm.org)
- ASTM E1032: [ASTM E1032 - 06 Standard Test Method for Radiographic Examination of Weldments](http://www.astm.org)
- ASTM E1032-01: [ASTM E1032-01 Standard Test Method for Radiographic Examination of Weldments](http://www.astm.org)
- ASTM E164: [ASTM E164 - 08 Standard Practice for Contact Ultrasonic Testing of Weldments](http://www.astm.org)
• ASTM E165: ASTM E165 - 09 Standard Practice for Liquid Penetrant Examination for General Industry

• ASTM E165-95: ASTM E165-95 Standard Test Method for Liquid Penetrant Examination

• ASTM E18-08: ASTM E18 - 08b Standard Test Methods for Rockwell Hardness of Metallic Materials

• ASTM E18-02: ASTM E18-02 Standard Test Methods for Rockwell Hardness and Rockwell Superficial Hardness of Metallic Materials


• ASTM E709-08: ASTM E709 - 08 Standard Guide for Magnetic Particle Testing

• ASTM E709-01: ASTM E709-01 Standard Guide for Magnetic Particle Examination


• ASTM E8: ASTM E8 / E8M - 09 Standard Test Methods for Tension Testing of Metallic Materials

• ASTM E94-04: ASTM E94 - 04 Standard Guide for Radiographic Examination

• ASTM E94-00: ASTM E94-00 Standard Guide for Radiographic Examination

ENFORM (Available through www.enform.ca)

• IRP 1: Critical Sour Drilling

• IRP 2: Completing and Servicing Critical Sour Wells

• IRP 4: Well Testing and Fluid Handling

• IRP 6: Critical Sour Underbalanced Drilling

• IRP 7: Standards for Wellsite Supervision of Drilling, Completion and Workovers

• IRP 8: Pumping of Flammable Fluids

• IRP 14: Non Water Based Drilling and Completion/Well Servicing Fluids

• IRP 18: Fire and Explosion Hazard Management

• IRP 22: Underbalanced and Managed Pressure Drilling Operations Using Jointed Pipe

• IRP 23: Lease Lighting Standards

NACE (Available through www.nace.org)
• NACE TM0187 98: Standard Test Method for Evaluating Elastomeric Materials in Sour Gas Environments
• NACE/ANSI Standard MR0175/ISO15156

**OTHER**

• Alberta OHS bulletin/publication GS006: *Best Practice – Working Safely in the Heat and Cold* (available through www.employment.alberta.ca under workplace health and safety publications)
• API Spec Q1: Specification for Quality Programs (available through www.api.org)
• ASME Section V and IX (available through www.asme.org)
• ASNT SNT-TC-1A (available through www.asnt.org)
• CAODC Technical Information Bulletin T-02-08 (regarding electrical bonding and grounding) (available through www.caodc.ca)
• SPE Paper 37067: High Pressure Flammability of Drilling Mud/Condensate/Sour Gas Mixtures in De-oxygenated Air for Use in Underbalanced Drilling (available through www.spe.org)
APPENDIX B:

Detailed Recommended Practices Regarding Non-Destructive Examination Of CT Strings

The recommended and best practices below are summarized from IRP 2: Completing and Servicing Critical Sour Wells.

NDE OF BIAS OR BUTT WELDS IN CT STRINGS

RADIOGRAPHIC TESTING (RT)

▷ RT should be conducted in accordance with ASTM E94 and ASTM E1032 using an ASTM rectangular image quality indicator (IQI).

▷ The IQI should be in accordance with Table 12 below for the appropriate wall thickness. The 2T hole should be clearly discernable in each radiograph of each weld.

<table>
<thead>
<tr>
<th>Nominal Wall Thickness (t)</th>
<th>ASTM Designation</th>
<th>Essential Hole</th>
</tr>
</thead>
<tbody>
<tr>
<td>t ≤ 0.150 inch (t ≤ 3.810 mm)</td>
<td>10</td>
<td>2T</td>
</tr>
<tr>
<td>0.150 inch &lt; t ≤ 0.250 inch (3.810 mm &lt; t ≤ 6.350 mm)</td>
<td>12</td>
<td>2T</td>
</tr>
<tr>
<td>0.250 inch &lt; t ≤ 0.375 inch (6.350 mm &lt; t ≤ 9.525 mm)</td>
<td>15</td>
<td>2T</td>
</tr>
</tbody>
</table>

ULTRASONIC SHEAR WAVE TESTING (UT)

▷ UT should be conducted in accordance with ASTM E164.

▷ The UT unit should be standardized using a reference standard both before and immediately after performing the UT inspection.

▷ The reference standard should contain at least one electron discharge machined (EDM) notch having the following dimensions:
  • length ≤ 6.350 mm (0.250 inch) long,
  • width = 0.254 mm (0.010 inch), and
• depth = 5% of the specified nominal wall thickness of the base metal. The minimum notch depth = 0.254 mm (0.010 inch).

LIQUID PENETRANT TESTING (PT)

PT should be performed in accordance with ASTM E165.

ACCEPTANCE CRITERIA FOR NDE OF WELDS

For RT, the acceptance criteria should be no indications in excess of the essential IQI hole.

For UT, the acceptance criteria should be no indication greater than 50% of the reference amplitude.

For PT, the acceptance criteria should be no relevant indications allowed, regardless of size.

FULL LENGTH NDE OF CT STRINGS

NDE PROCEDURE AND EQUIPMENT

The following automated methods are acceptable for full length NDE of CT strings:

- ultrasonic inspection in accordance with ASTM E273,
- electro-Magnetic Inspection (EMI) in accordance with ASTM E570, and
- eddy current inspection in accordance with ASTM E309.

The NDE procedure shall require standardization (calibration) of the inspection unit with a reference standard both prior to and immediately following the inspection, as well as any time a malfunction of the unit is suspected.

The NDE equipment should be adjusted to produce well defined indications from the reference indicators when the reference standard is scanned by the inspection unit in a manner simulating the actual inspection of the product.

The signals from the reference indicators should be clearly labelled and separated on the record obtained from the NDE equipment.

If the NDE equipment is capable of alerting the operator for indications exceeding a specific limit (threshold), the limit should be set at the average minimum signal level observed while scanning the reference standard.

The running speed of the CT through the NDE equipment should be adjusted to allow 100% coverage of the inspected length.

All indications from NDE exceeding threshold limits should be documented in
the NDE report and maintained in the CT string records.

**NDE SYSTEM CAPABILITY RECORDS**

The NDE service provider should maintain NDE system records verifying the system capabilities in detecting the reference indicators used to establish the equipment test sensitivity. The verification and records should cover, as a minimum, the following criteria:

- coverage calculation (i.e. scan plan) including wall thickness verification,
- capability for the intended wall thickness,
- repeatability,
- transducer orientation that provides detection of defects typical of the manufacturing process,
- documentation demonstrating that defects typical of the manufacturing process are detected using the NDE method,
- threshold setting parameters,
- NDE system operating procedures,
- NDE equipment description,
- NDE personnel qualification information, and
- dynamic test data demonstrating the NDE system/operation capabilities under dynamic production inspection/test conditions.

**NDE Reference Standards**

The reference standards used to standardize automated UT, eddy current, or magnetic flux leakage units should meet the requirements of this section.

**DIMENSIONS AND PROPERTIES (APPLIES TO AUTOMATED UT, EDDY CURRENT AND MAGNETIC FLUX LEAKAGE UNITS)**

Specified nominal outside diameter is the same as the CT string being inspected.

Specified nominal wall thickness ≥ the CT string being inspected.

For tapered CT strings, two reference standards should be used corresponding to the maximum and minimum specified wall thickness of the CT string to be inspected.

Standardization of the NDE unit should be performed on the thicker standard, with the thinner standard used as a check.

**REFERENCE INDICATORS**

Each reference standard should include the reference indicators described in
the following subsections.

Individual reference indicators should be separated sufficiently on the reference standard so as to generate distinct recordable signals from the NDE equipment.

THROUGH-DRILLED HOLES (APPLIES TO AUTOMATED UT, EDDY CURRENT, AND MAGNETIC FLUX LEAKAGE UNITS)

The NDE reference standard should include at least one through-drilled hole. Through-drilled holes should be drilled perpendicular to the surface of the reference standard at the weld zone edge:

- 1.588 mm (0.063 inch) – both new and used CT, and
- 0.794 mm (0.031 inch) – used when agreed upon between customer and inspector.

LONGITUDINAL NOTCHES (APPLIES ONLY TO AUTOMATED UT AND MAGNETIC FLUX LEAKAGE UNITS)

The outer surface of the NDE reference standard should include at least one longitudinal EDM notch with the following dimensions:

- length = 6.35 mm (0.25 inch) at full depth
- depth = 10% of the specified nominal wall thickness (maximum); the minimum depth = 0.305 mm (0.012 inch)
- width = 0.254 mm (0.010 inch)

For CT strings with OD = 1.5 inches 38.10 mm (1.5 inches), the inner surface of the NDE reference standard should include at least one longitudinal EDM machined notch with the following dimensions:

- length = 6.35 mm (0.25 inch) at full depth
- depth = 10% of the specified nominal wall thickness (maximum); the minimum depth = 0.305 mm (0.012 inch)
- width = 0.254 mm (0.010 inch)

TRANSVERSE NOTCHES (APPLIES ONLY TO AUTOMATED UT AND MAGNETIC FLUX LEAKAGE UNITS)

The outer surface of the NDE reference standard should include at least one transverse EDM notch with the following dimensions:

- length = 6.35 mm (0.25 inch) at full depth
- depth = 10% of the specified nominal wall thickness (maximum); the minimum depth = 0.305 mm (0.012 inch)
- width = 0.254 mm (0.010 inch)

For CT strings with OD = 38.10 mm (1.5 inches), the inner surface of the NDE
reference standard should include at least one transverse EDM machined notch with the following dimensions:

- length = 6.35 mm (0.25 inch) at full depth
- depth = 10% of the specified nominal wall thickness (maximum); the minimum depth = 0.305 mm (0.012 inch)
- width = 0.254 mm (0.010 inch)

**WALL LOSS AREA – USED CT (APPLIES ONLY TO AUTOMATED UT AND MAGNETIC FLUX UNITS)**

The outer surface of the NDE reference standard for used CT should include a wall loss area covering 645.2 – 967.7 mm² (1.00-1.50 in²) with the following depth. The wall loss area should make a smooth transition to the surrounding material (no sharp edges):

- 0.127 mm (0.005 inch) for specified nominal wall thickness 2.794 mm (0.110 inch)
- 0.008 inch (0.203 mm) for specified nominal wall thickness ≥ 2.794 mm (0.110 inch)

**Prove-Up of NDE Indications**

Any indication that produces a signal equal to or greater than the reference standard is to be treated as follows:

- it should be marked with a non-damaging method, and
- it shall be evaluated and proved-up with RT, UT, PT, and/or magnetic particle testing (MT) as appropriate and accepted by customer.
- All prove-up of indications and repairs of blemishes should be documented in the NDE report.

**Non-Sour Service CT Strings**

If the prove-up of an indication from NDE on a CT string for non-sour service confirms a physical blemish, the CT string should not be acceptable for non-sour service operations unless one of the following conditions is met:

1. the external blemish can be removed per the “Repair of Blemishes” section below—if the wall thickness after the repair is less than 90% of the specified nominal wall thickness, the user of the CT string should provide compelling evidence the CT string is suitable for the intended service as per the requirements of sections 3.2 Evaluating the Suitability of CT Strings and 3.3 Assessing Mechanical Strength of this IRP;
2. the section of tubing containing the blemish can be cut out of the CT string—if necessary, the cut ends of the string can be spliced together with a butt weld or mechanical connector;
3. the user of the CT string provides compelling evidence that leaving the
blemish in place will not render the CT string unsuitable for the intended service as per the requirements of sections 3.2 Evaluating the Suitability of CT Strings and 3.3 Assessing Mechanical Strength of this IRP.

**Sour Service CT Strings**

- If the prove-up of an indication from NDE on a CT string for sour service confirms a physical blemish, the CT string should not be acceptable for sour service operations unless one of the following conditions is met:

1. the external blemish can be removed per the “Repair of Blemishes” section below—the minimum allowable wall thickness after the repair should be 90% of the specified nominal wall thickness;

2. the section of tubing containing the blemish can be cut out of the CT string—if the service is **not** critical sour, the cut ends of the string can be spliced together, as per Section 3.5 Welding CT Strings of this IRP.

**REPAIR OF BLEMISHES**

- A blemish revealed by NDE should be repaired by removing material parallel to the tubing axis.

- Material should not be removed at any angle transverse to the tubing axis. (Even shallow scratches at small angles to the tubing axis can serve as effective crack initiation sites.)

- Files, belt sanders, or cylindrical rotary stones should be used instead of flat rotary grinding disks for repairing blemishes to the CT string.

- Bulk material should be removed over a length at least twice the tubing OD.

- The exposed surface should be as smooth as possible and free of irregularities.

- The edges of the repaired area should make a smooth transition to the undisturbed material.

- After the bulk material removal, the exposed surface should be polished manually in the longitudinal direction. Use progressively finer emery cloth, beginning with 180-240 grit and ending with 400-600 grit.

**REINSPECTION OF REPAIRED SURFACES**

- The repaired area should be reinspected with RT, UT, PT, and/or MT as deemed appropriate.

- Each repaired area should be subjected to UT compression wave inspection to verify the remaining wall thickness.
ACCEPTANCE CRITERIA FOR REPAIRED SURFACES

- The acceptance criteria for surfaces repaired by polishing should be as follows:
  - no visible flaws or cracks regardless of size,
  - no indication that produces a signal equal to or greater than the reference standard,
  - no dents,
  - no visible scratches having a transverse component,
  - surface finish equal to or smoother than the surrounding undisturbed material, and
  - CT string re-evaluated as per sections 3.2 Evaluating the Suitability of CT Strings and 3.3 Assessing Mechanical Strength of this IRP.

NDE DOCUMENTATION

- The complete results of all NDE performed on a CT string should be documented by the NDE technician who performed the inspection that includes the following:
  - serial number of the CT string,
  - size, weight, and material of the CT string,
  - NDE methods used,
  - details on NDE equipment including serial numbers of all calibration standards and the last date of their verification,
  - NDE procedures followed including reference number and revision level or date,
  - results of the NDE including all indications noted and the results of the ultimate prove-up of each indication, and
  - printed name and signature of the NDE technician performing the inspection, as well as the date of the inspection.
## APPENDIX C:

### Basic Reference for Elastomer Selection –
Outline of Typical Properties for Common Oilfield Elastomers

<table>
<thead>
<tr>
<th>Generic Category*</th>
<th>ASTM Designation</th>
<th>Hardness Range (Shore A)</th>
<th>H₂S Resistance</th>
<th>Liquid Hydrocarbon Resistance</th>
<th>Temp Rating** (°C)</th>
<th>Common Trade Name Examples</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural rubber</td>
<td>NR</td>
<td>25-100</td>
<td>Fair</td>
<td>Poor</td>
<td>-60 to 80</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Sometimes used for BOP elements</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Good low temperature points</td>
</tr>
<tr>
<td>Polychloroprene</td>
<td>CR</td>
<td>30-95</td>
<td>Fair</td>
<td>Fair</td>
<td>-50 to 90</td>
<td>Neoprene</td>
<td>High swelling in oil</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Good low temperature properties</td>
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<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Better H₂S resistance than NBR</td>
</tr>
<tr>
<td>Epichlorohydrin</td>
<td>CO</td>
<td>50-85</td>
<td>Fair</td>
<td>Fair</td>
<td>-40 to 150</td>
<td>Hydrin 100 Herclor H</td>
<td>Good low temperature properties</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Has limited resistance to methanol</td>
</tr>
<tr>
<td>Ethylene propylene diene</td>
<td>EPDM</td>
<td>65-90</td>
<td>Good</td>
<td>Poor</td>
<td>-50 to 150</td>
<td>Nordel</td>
<td>Good high temperature</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Used mainly for geothermal applications</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Excellent water resistance</td>
</tr>
<tr>
<td></td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Large swelling in oil (unsuitable for general oilfield)</td>
</tr>
<tr>
<td>Nitrile</td>
<td>NBR</td>
<td>40-95</td>
<td>Poor</td>
<td>Good</td>
<td>-50 to 120</td>
<td>Buna N Hycar</td>
<td>Most common oilfield elastomer</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Used commonly for packer, BOP elements</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Low temperature rating can vary</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Various levels of acrylonitrile available</td>
</tr>
<tr>
<td>Hydrogenated nitrile</td>
<td>HNBR</td>
<td>40-90</td>
<td>Fair</td>
<td>Good</td>
<td>-50 to 120</td>
<td></td>
<td>Improved H₂S and amine resistance over standard nitrile</td>
</tr>
<tr>
<td>Fluorocarbon</td>
<td>FKM</td>
<td>60-90</td>
<td>Fair</td>
<td>Good</td>
<td>-30 to 200</td>
<td>Viton Fluorel</td>
<td>Common oilfield elastomer often replaces NBR for higher temperatures</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Can harden in amine inhibitors and sulphur solvents</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Has limited methanol resistance</td>
</tr>
<tr>
<td>Tetrafluoroethylene-</td>
<td>TFE P</td>
<td>60-95</td>
<td>Good</td>
<td>Fair</td>
<td>0 to 200</td>
<td>Aflas</td>
<td>Excellent general thermo-chemical resistance</td>
</tr>
<tr>
<td>propylene</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Poor mechanical properties below 0° C</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Moderate swelling in hydrocarbons</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Better in amine inhibitors than FKM</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Mainly downhole applications</td>
</tr>
<tr>
<td>Perfluoroelastomer</td>
<td>FFKM</td>
<td>65-95</td>
<td>Good</td>
<td>Good</td>
<td>-20 to 230</td>
<td>Kalrez Chemraz</td>
<td>Excellent general thermo-chemical resistance</td>
</tr>
<tr>
<td></td>
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<td></td>
<td></td>
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<td>Poor mechanical properties below 0° C</td>
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<td>Superior amine and hydrocarbon resistance</td>
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<td></td>
<td></td>
<td>Mainly used downhole for O-ring or chevron-ring packing</td>
</tr>
</tbody>
</table>

* There is no intent to limit the choice of elastomers to these materials only.

**Not all elastomer products in a generic category will have the full temperature range given.
APPENDIX D:

Equipment Symbols used in Section 2 Accumulator Diagrams