

Service Rig Operation Safety

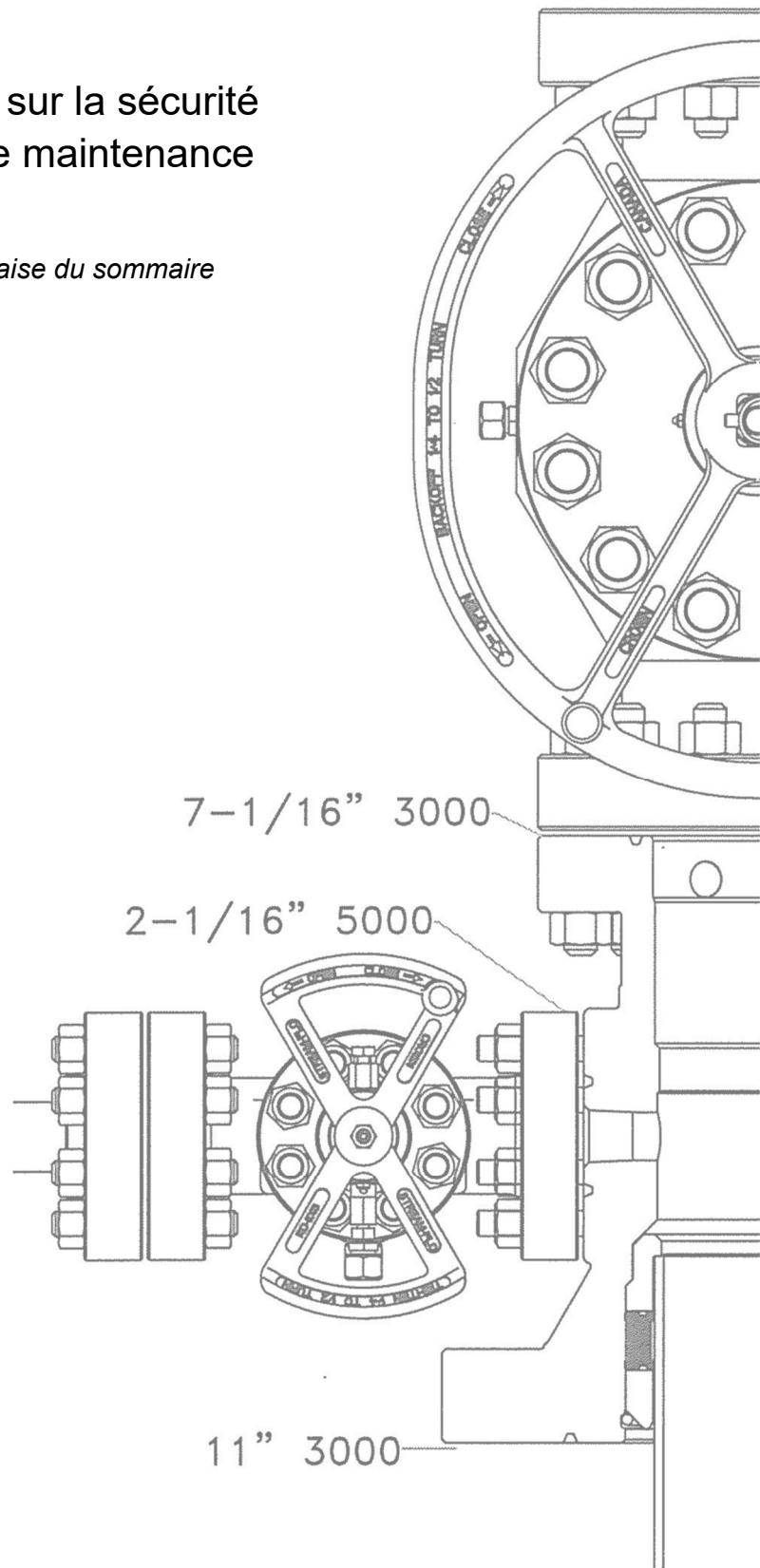
Guidelines and Interpretation Notes

March 31, 2025

Bulletin d'application et directives sur la sécurité de l'exploitation des plateformes de maintenance

Le 31 mars 2025

Le présent document contient la traduction française du sommaire



K'áhshó got'jne xədə k'é hederi ɬedjhtl'é yeriniwé ni dé dúle.

Dene Kədá

ʔerihkt'ís Dëne Sųłiné yati t'a huts'elkér xa beyáyatı theɂa ɬat'e, nuwe ts'ën yólti.

Dëne Sųłiné

Edi gondı dehgáh got'je zhatié k'éé edat'éh enahddhę nide naxets'é edahli.

Dene Zhatié

Jii gwandak izhii ginjìk vat'atr'ijahch'uu zhit yinohthan jì', diits'at ginohkhìi.

Dinjii Zhu' Ginjik

Uvanittuaq ilitchurisukupku Inuvialuktun, ququaqluta.

Inuvialuktun

Inuktitut

Hapkua titiqqat pijumagupkit Inuinnagtun, uvaptinnut hivajarlutit.

Inuinnagtun

kīspin ki nitawihtīn ē nīhiyawihk ōma ācimōwin, tipwāsinān.

nēhiyawēwin

Tłjcho yatı k'èè. Dı wegodi newo dè, gots'o gonede.

Tłjcho

Indigenous Languages

request Indigenous_languages@gov.nt.ca

Contents

1	Introduction	1
2	Sommaire	4
3	CAOEC Compliance	6
4	Well Control Equipment	7
4.1	Minimum specifications	8
4.2	Equipment testing	10
4.3	Cold weather operations	13
4.4	Sour gas operations	14
4.5	Alert device	15
4.6	Blow out prevention system	16
4.6.1	BOP stack	16
4.6.2	Accumulator system	17
4.6.3	Backup nitrogen system	18
4.6.4	BOP controls	19
4.7	Bleed-off / kill system	20
4.7.1	Circulation manifolds	20
4.7.2	Rig tanks and fluid volume monitoring systems	21
4.7.3	Tubing pressure gauge assemblies	21
4.7.4	Bleed-off/kill lines	21
4.7.5	Pressure vessels and pressure vessel inlet lines	23
4.7.6	Flare lines	23
5	Other Equipment on Site	25
5.1	Electrical and fired heating equipment	26
5.2	Equipment with internal combustion engines	28
6	Well Site Spacing	30
7	Specific Operations	32
7.1	Overbalanced milling	33
7.2	Underbalanced milling and shallow wellbore plugs	34
8	Administrative Controls	36
8.1	Well site supervision	37
8.2	Rig crew certification	38
8.3	BOP drills	39

Service Rig Operation Safety Guidelines and Interpretation Notes

8.4	Operator and contractor inspections	40
8.5	Onsite documentation for well control	41
9	Regulator's Approval.....	42

Service Rig Operation Safety Guidelines and Interpretation Notes

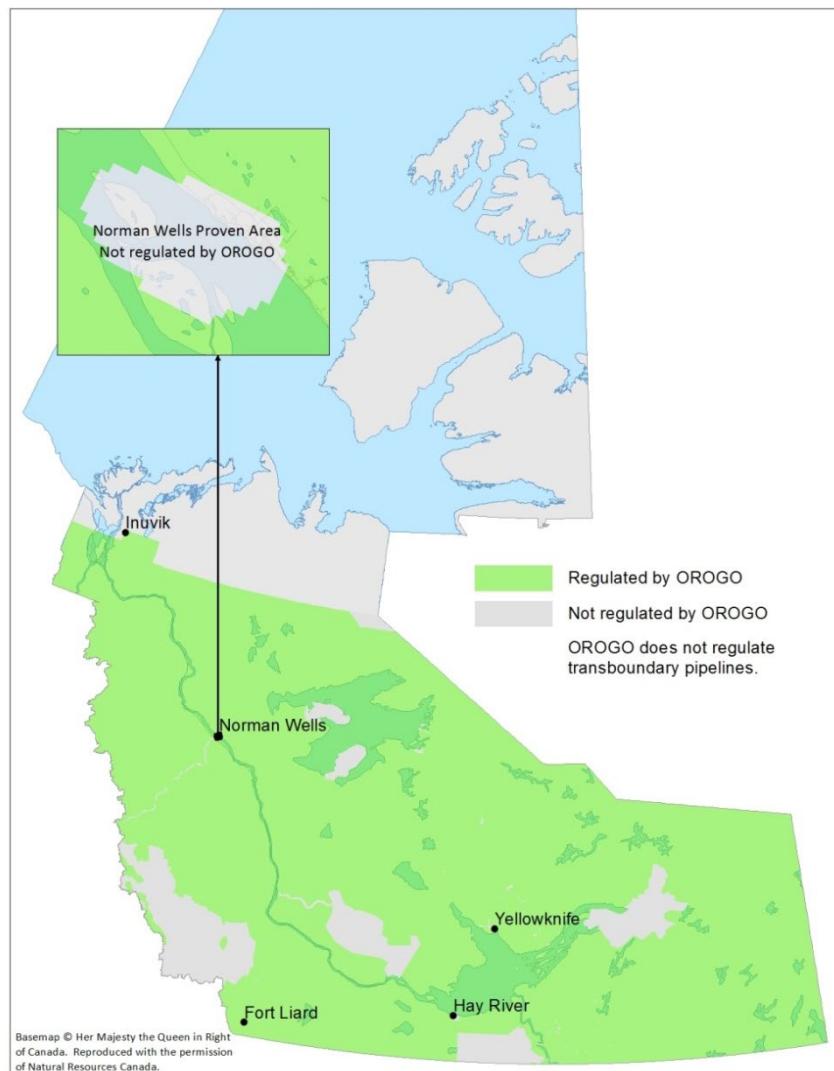
1 Introduction

Purpose	<p>The <i>Service Rig Operation Safety Guidelines and Interpretation Notes</i> (Guidelines) provide guidance for operators on in-field requirements for service rigs and associated equipment.</p>
Information in French	<p>Section 2 of these Guidelines contains a French language summary of the document, as required under the <i>Standards for French Language Communications and Services</i> issued by the Government of the Northwest Territories in August 2024.</p> <p>To obtain a copy of this document in French, please call 867-767-9097.</p>
Objectives	<p>The objectives of these Guidelines are to:</p> <ul style="list-style-type: none">• Support compliance with the <i>Oil and Gas Operations Act</i> (OGOA) and its regulations.• Reflect the context of oil and gas activities in the Regulator's jurisdiction.• Be consistent with the requirements of other western Canadian regulators, in particular the Alberta Energy Regulator's <i>Directive 037: Service Rig Inspection Manual</i>.
Legislative requirements	<p>The <i>Oil and Gas Drilling and Production Regulations</i> require operators to ensure that:</p> <ul style="list-style-type: none">• Reliably operating well control equipment is installed to control kicks, prevent blow-outs, and safely carry out all well activities and operations (section 36(1)).• Pressure control equipment is pressure-tested on installation and as often as necessary to ensure its continued safe operation (section 37).
Minimum requirements	<p>The Guidelines set out the minimum requirements for operators. Operators may suggest alternative approaches that are demonstrated to meet or exceed the same standards for the protection of human safety and the environment.</p>
Regulator's discretion	<p>Application of these Guidelines is subject to the Regulator's discretion under OGOA.</p>
Authority	<p>These Guidelines are issued by the Regulator under section 18 of the <i>Oil and Gas Operations Act</i> (OGOA).</p>

Service Rig Operation Safety Guidelines and Interpretation Notes

Jurisdiction

These Guidelines apply in the Regulator's jurisdiction, as shown on the following map.



Application

These Guidelines apply to all operations conducted with a service rig except operations on:

- Critical sour wells.
- Acid gas wells.
- Wells without a surface casing.

Please contact OREGO to discuss safety requirements before applying for operations on these types of wells.

Service Rig Operation Safety Guidelines and Interpretation Notes

Definition: critical sour well A well is considered **critical sour** based on its location and known H₂S release rate upon completion, as shown in the following table.

A critical sour well is located	and has a known H₂S release rate upon completion of
Within 500 meters of the boundaries of a population centre	0.01 to 0.09 cubic meters per second (m ³ /s)
Within 1.5 kilometers of the boundaries of a population centre	0.1 and 0.29 m ³ /s
Within 5 kilometers of the boundaries of a population centre	0.3 and 1.99 m ³ /s
Anywhere in the Regulator's jurisdiction	2.0 m ³ /s or more.

Definition: population centre A **population centre** is any incorporated, unincorporated, or self-governing community in the Regulator's jurisdiction, any seasonal camp or similar area, or as otherwise determined by the Regulator.

A list of Northwest Territories communities is available on the website of the [Department of Municipal and Community Affairs](#).

Definition: acid gas well An **acid gas well** is a well that produces a combination of any amount of H₂S and CO₂ or into which a combination of any amount of H₂S and CO₂ is injected.

Plain language These Guidelines have been written for use by operators in the field and during the design of well programs. Plain language is used where possible to make them accessible to as many readers as possible.

Regulations are paramount Where a conflict exists between the Guidelines and the *Oil and Gas Operations Act* (OGOA) or its regulations, OGOA and the regulations are paramount.

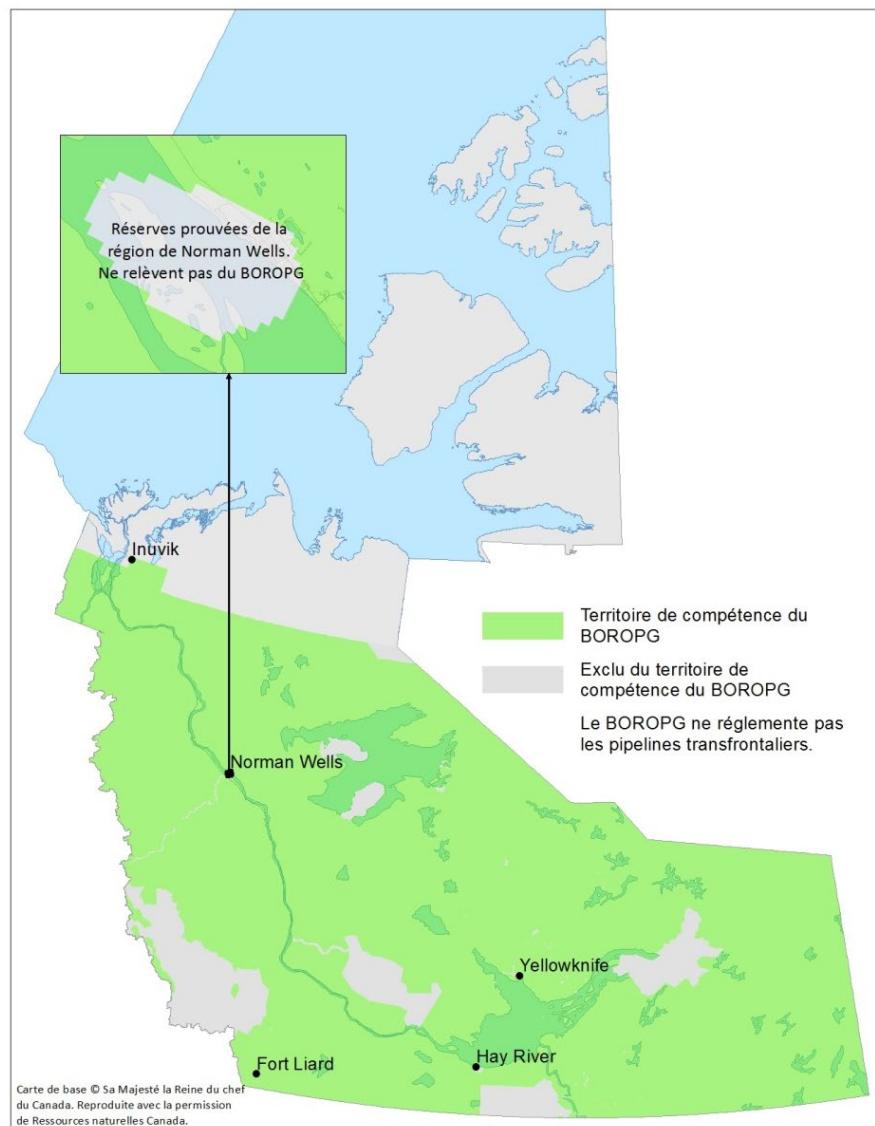
2 Sommaire

But	Le <i>Bulletin d'application et directives sur la sécurité de l'exploitation des plateformes de maintenance</i> (Directives) décrit les exigences sur le terrain pour les exploitants de plateformes de maintenance et de l'équipement connexe.
Objectifs	Objectifs des Directives :
	<ul style="list-style-type: none">• Appuyer la conformité à la <i>Loi sur les opérations pétrolières</i> (LOP) et ses règlements.• Prendre en compte le contexte dans lequel se déroulent les activités pétrolières et gazières sur le territoire de compétence relevant de l'organisme de réglementation.• Assurer la cohérence avec les exigences des autres organismes de réglementation de l'Ouest canadien, en particulier la directive 037 de l'Alberta Energy Regulator, Manuel d'inspection des plateformes de service.
Exigences prévues par la loi	Le <i>Règlement sur le forage et la production de pétrole et de gaz</i> exige des exploitants :
	<ul style="list-style-type: none">• que l'équipement fiable de contrôle du puits soit en place pour contrôler les venues, prévenir les éruptions et exécuter en toute sécurité les activités et les travaux relatifs au puits [paragraphe 36(1)];• que l'équipement de contrôle de pression soit soumis à une épreuve sous pression au moment de son installation, et par la suite, aussi souvent que cela est nécessaire pour en garantir la sécurité de fonctionnement [paragraphe 37].
Pouvoir discrétionnaire de l'organisme de réglementation	La LOP accorde à l'organisme de réglementation un pouvoir discrétionnaire dans l'application des présentes Directives.
Autorité	L'organisme de réglementation publie les présentes Directives en vertu de l'article 18 de la <i>Loi sur les opérations pétrolières</i> (LOP).

Service Rig Operation Safety Guidelines and Interpretation Notes

Compétence

Ces Directives s'applique au territoire de compétence relevant de l'organisme de réglementation, tel qu'indiqué sur la carte ci-dessous.



Prédominance du Règlement

En cas de conflit, la LOP ou ses règlements l'emportent sur les présentes Directives.

3 CAOEC Compliance

Requirements

Operators must maintain compliance with the current editions of the following [Recommended Practices](#) issued by the Canadian Association of Energy Contractors (CAOEC):

- Recommended Practice 3.0: Inspection and Certification of Masts
- Recommended Practice 4.0: Inspection and Certification of Overhead Equipment
- Recommended Practice 6.0: Inspection and Certification of Blowout Preventers
- Recommended Practice 10.0: Inspection of Drawworks Brake Load Path Components
- Recommended Practice 11.0: Inspection and Certification of Carrier Mounted Equipment

Exception: If there is a conflict between the listed Recommended Practices and these Guidelines, the Guidelines apply.

4 Well Control Equipment

Contents

This section contains requirements that apply to all well control equipment:

- Minimum specifications
- Equipment testing
- Cold weather operations
- Sour gas operations
- Alert device

It also contains requirements for specific well control equipment:

- Blow out prevention system
- Bleed-off system / kill system

Service Rig Operation Safety Guidelines and Interpretation Notes

4.1 Minimum specifications

Contents	This section contains the minimum specifications for the three classes of servicing blowout prevention (BOP) systems: <ul style="list-style-type: none">• Class I systems• Class II systems• Class III systems
Class I systems	Class I servicing BOP systems are used for wells with: <ul style="list-style-type: none">• Reservoir pressure < 5,500 kPa and• No H₂S. Class I servicing BOP systems have the following characteristics: <ul style="list-style-type: none">• The well is not killed.• A pipe and blind ram blowout preventer unit may be used instead of an annular preventer (the position of the ram may be interchanged).
Class II systems	Class II servicing BOP systems are used for wells with: <ul style="list-style-type: none">• A production casing flange rated to ≤ 21,000 kPa and• H₂S < 10 moles/kilomole. Class II servicing BOP systems have the following characteristics: <ul style="list-style-type: none">• The pressure rating of the preventers is equal to or greater than the production casing flange rating, or the formation pressure, whichever is less.• The positioning of the pipe and blind rams may be interchanged.• The spool may have threaded side outlet (and valve) if the wellhead has threaded fittings.• A flanged blowout preventer port (and valve) below the lowest set of rams may replace the spool (the valve may be threaded if wellhead has threaded fittings).• All lines are 50 mm in diameter.
Class III systems	Class III servicing BOP systems are used for wells with: <ul style="list-style-type: none">• A production casing flange rated to > 21,000 kPa or• A production casing flange rated to ≤ 21,000 kPa and H₂S > 10 moles/kilomole. Class III servicing BOP systems have same characteristics as Class II wells.
Connectors	Acceptable types of connectors are based on the production casing flange rating or the formation pressure, whichever is less. Connectors must meet manufacturer specifications.

Service Rig Operation Safety Guidelines and Interpretation Notes

Clamp type connectors that serve the same function as a high-pressure flanged assembly may be used in the BOP system to replace a flanged connection.

All flange or clamp type connectors must be pressure tested at the connection whenever a connection is loosened or disassembled.

All connectors must meet the standards of the API (American Petroleum Institute) or the American National Standards Institute (ANSI). Non-API or -ANSI connectors must be certified by the original equipment manufacturer or a professional engineer. Documentation must be provided as required by the well approval.

4.2 Equipment testing

Contents This section contains requirements for testing well control equipment, including:

- Accountability for testing
- Required tests and frequency
- Recording results
- Pressure test procedures
- Expected pressure test results
- BOP three function test procedures
- Expected three function test results

Accountability for testing The Rig Manager is accountable for testing the well control equipment in compliance with this section.

Required tests and frequency The required tests and their frequency are summarized in the following table:

Test	Frequency
Pressure test	Before start of operations.
BOP three function test	Before start of operations. Minimum every 7 days after initial test during the same operation.
BOP component test	Daily: annular and pipe rams. Daily: blind rams (when the string is out of the hole). Minimum before start of operations and every 7 days: valves.

Recording results Test results are recorded on the tour sheet and in the daily reports. BOP function test results must include a list of the components tested.

Pressure test procedures The procedures for a pressure test are:

1. Pressure test the connection between the stack and the wellhead, the stabbing valve, the bleed-off manifold, and the bleed-off/kill lines by:
 - a) Conducting a low-pressure test to 1,400 kPa on each ram preventer.
 - b) Conducting a high-pressure test on each ram preventer, the full opening safety valve, and the connection between the stack and the wellhead. Test to the wellhead pressure rating or the formation pressure, whichever is less.
 - c) Testing the annular preventer to 7,000 kPa or the formation pressure, whichever is less.

Service Rig Operation Safety Guidelines and Interpretation Notes

- d) Testing all valves in the bleed-off/kill line individually to the same pressure as the manifold, to the wellhead pressure rating, or to the formation pressure, whichever is less.
2. Pressure test the BOP to wellhead connection to the wellhead pressure rating or to the formation pressure, whichever is less. The procedure is based on what is present in the wellbore, as follows:

If no tubing is in the well, and a formation is open to the wellbore:

- a) A packer may have to be run in the casing to permit pressure testing.
- b) The tubing hanger may be run on the bottom of a joint of tubing and landed in the tubing spool (set screws secured).
- c) Testing can then take place by pressuring up below a closed preventer.

If tubing is in the well and the formation is open to pressure:

- a) A pup joint can be screwed into the tubing hanger and testing can take place by pressuring up below a closed preventer.
- b) The pup joint must be blanked on the bottom and perforated above the blank if pressure testing the stabbing valve along with the BOP.

If using a slip type wellhead:

- a) A tubing hanger designed for use with a slip type wellhead may be landed in the tubing spool after the slips, seals, and tubing head adapter have been removed.
- b) A pup joint can be screwed into the tubing hanger and testing can take place by pressuring up below a closed preventer.
- c) The pup joint must be blanked on the bottom and perforated above the blank if pressure testing the stabbing valve along with the BOP.

Expected pressure test results

All tests are expected to demonstrate that well control equipment complies with these Guidelines.

For pressure tests, all components must maintain a stabilized pressure of at least 90% of the test pressure over a 10-minute interval.

Loss of Pressure: If there is a loss of pressure during the test, determine whether the issue is with the tubing hanger or the BOP, as follows:

1. Maintain the required pressure on the wellhead while the pipe rams (or annular) and the wellhead connection are monitored for leaks.
2. If there are no leaks within the BOP connections, the test is

Service Rig Operation Safety Guidelines and Interpretation Notes

satisfactory but the operator must replace the faulty tubing hanger.

3. After the faulty tubing hanger is replaced, the operator must conduct new, satisfactory pressure test to confirm the repair.

Exception: If an electrical submersible pump is in use, a pressure test of the wellhead connection cannot be conducted. This is acceptable.

Prohibition: Well control equipment that does not comply with these Guidelines must be taken out of service immediately and repaired or replaced.

BOP three function test procedures

The procedure for a BOP three function test is:

1. Bleed the system down to recharge pressure setting.
2. Turn off the accumulator pump.
3. Function the pipe ram (closed) and record the closing time.
4. If there is no work string or wireline down hole, function the blind ram (closed) and record the closing time; or
If there is a work string or wireline down hole, function the pipe ram (open) and record the opening time and final stabilized pressure.
5. Function the annular (closed) and record the closing time and final stabilized pressure.
6. Turn on the accumulator pump and record recharge time and stabilized pressure.

Expected three function test results

All tests are expected to demonstrate that well control equipment complies with these Guidelines, including the closing times contained in section 4.6.2.

For BOP three function tests, the final stabilized pressure cannot drop below 8400 kPa and the accumulator must recharge to operating pressure within 5 minutes of turning on the accumulator pump.

Prohibition: Well control equipment that does not comply with these Guidelines must be taken out of service immediately and repaired or replaced.

4.3 Cold weather operations

Requirements If the temperature is below 0°C, not including wind chill:

- The BOP stack, all associated valves, the circulation manifold, and the accumulator system must be heated to maintain effectiveness.
- The bleed-off, kill, diverter, and flare lines must be:
 - Void of fluid traps;
 - Blown out with air; and
 - Filled with a non-freezing fluid capable of being mixed with water without separating or heated.
- A boiler with a remote steam nozzle must be available and able to reach the entire work site.
- The stabbing valve must be kept ice free.

4.4 Sour gas operations

Requirements	During operations on sour gas wells, all pressure-containing components within the BOP, bleed-off, and kill systems must meet the requirements of the current ANSI/National Association of Corrosion Engineers (NACE) <u>MR0175: Petroleum and Natural Gas Industry – Materials for Use in H₂S-Containing Environments in Oil and Gas Production.</u>
---------------------	--

Service Rig Operation Safety Guidelines and Interpretation Notes

4.5 Alert device

Mandatory crew alert device An operable alert device must be installed on the service rig for alerting the crew of events such as well control situations or BOP drills.

Service Rig Operation Safety Guidelines and Interpretation Notes

4.6 Blow out prevention system

Contents	This section contains requirements for BOP systems used in service rig operations, including: <ul style="list-style-type: none">• The BOP stack• The accumulator system• The backup nitrogen system• The BOP controls
General BOP system requirements	<p>BOP equipment must be installed and maintained on all wells. It must be:</p> <ul style="list-style-type: none">• Able to shut off a flow at the wellhead, even if any type of tool or equipment is being used in the well.• Compliant with the specifications in these Guidelines. <p>If redundant BOP equipment used, it must be:</p> <ul style="list-style-type: none">• Always functional (unless the hydraulic lines are disconnected).• Included in all pressure testing.• Included in accumulator and backup nitrogen system volume calculations.• Locked out when not in service (control handles removed or lines disconnected).

4.6.1 BOP stack

Contents	This section contains requirements for BOP stacks used in service rig operations, including: <ul style="list-style-type: none">• Double drilling or studding• Casing bowls• Stabbing valves
Double drilling or studding	BOP equipment may be double drilled or studded. However: <ul style="list-style-type: none">• Double studding the BOP body to accept two sizes of API flanges (for equipment that may have a lower pressure rating) does not result in the derating of the BOP.• Double drilling or studding flanged BOP equipment to accommodate connections to other API equipment with a lower pressure rating results in a derating of the flange to the lower working pressure. If the modified flange is to be used in an application requiring its original pressure rating, the operator must provide documentation from the original equipment manufacturer or a professional engineer that the flange is certified for the higher pressure rating as required by the well approval.

Service Rig Operation Safety Guidelines and Interpretation Notes

Casing bowls	Casing bowls must have: <ul style="list-style-type: none">• A casing flange that is an integral part of the bowl.• At least one threaded, flanged, or studded side outlet and valve.
Stabbing valves	All service rigs must be equipped with a stabbing valve rated for maximum operating pressure. Stabbing valves must be: <ul style="list-style-type: none">• Fully opening and equipped with a valve operating wrench.• Stored in the open position.• Operable and readily accessible on the rig floor.• Same diameter as the work string it is being attached to.• Compatible with all tubing string thread types in use during operations.• Equipped with removable handles which are readily available on the rig floor. A full open hanger cap assembly may be used in place of handles.

4.6.2 Accumulator system

Contents	This section contains requirements for accumulator systems, including: <ul style="list-style-type: none">• Hydraulic fluid capacity• Sizing calculations• Recharge capacity• Speed• Venting• Installation
Hydraulic fluid capacity	The accumulator system must be able to provide, without recharging, hydraulic fluid of sufficient volume and pressure to close the annular preventer on the pipe, close one ram preventer, and retain a minimum pressure of 8,400 kPa on the accumulator system.
Sizing calculations	Accumulator sizing calculations must be completed as described in the Energy Safety Canada Well Service Blowout Prevention course. Calculations must be completed before operations begin to ensure appropriate equipment is in use.
Recharge capacity	The accumulator system must include an automatic pressure-controlled recharge pump that recovers, within 5 minutes, the pressure drop resulting from the function test of the BOP components.
Speed	The accumulator system must be able to: <ul style="list-style-type: none">• Close any ram-type BOP within 30 seconds.• Close any annular type BOP:<ul style="list-style-type: none">◦ Within 60 seconds (wellbore diameter \leq 350 mm).◦ Within 90 seconds (wellbore diameter $>$ 350 mm).

Service Rig Operation Safety Guidelines and Interpretation Notes

Venting	The accumulator system must be designed so the vent on the accumulator reservoir vents outside the building, through the side or top of building.
Installation	<p>The accumulator system must be:</p> <ul style="list-style-type: none">• Readily accessible.• Connected to the BOP stack with hydraulic BOP lines (steel or non-steel) of working pressure equal to or greater than the manufacturer's design pressure of the accumulator.• Equipped with:<ul style="list-style-type: none">◦ A check valve located between the accumulator charge pumps and the accumulator bottles.◦ An accurate gauge to determine accumulator system pressure.◦ Readily accessible fittings and gauges to determine the pre-charge pressure of the accumulator bottles.• Housed to ensure the system can be protected from the well in the event of an uncontrolled flow.• Connected to a backup nitrogen system (see section 4.6.3).

4.6.3 Backup nitrogen system

Contents	This section contains requirements for backup nitrogen (N ₂) systems, including: <ul style="list-style-type: none">• N₂ capacity• Sizing calculations• Installation
N₂ capacity	The backup N ₂ system must be capable of providing sufficient volume and pressure to close the annular preventer on the pipe, close one ram preventers, and retain a minimum pressure of 8,400 kPa on the N ₂ backup system.
Sizing calculations	<p>N₂ backup sizing calculations must be completed as described in the Energy Safety Canada Well Service Blowout Prevention course.</p> <p>Calculations must be completed before operations begin to ensure appropriate equipment is in use.</p>
Installation	<p>The backup N₂ system must be:</p> <ul style="list-style-type: none">• Readily accessible.• Connected to operate the BOPs and not allow the N₂ to discharge into the accumulator reservoir or the accumulator bottles (including use of isolation valves).• Equipped with a gauge to determine the backup N₂ pressure or have a gauge readily available for installation.

Service Rig Operation Safety Guidelines and Interpretation Notes

- Housed to ensure the system can be protected from the well in the event of an uncontrolled flow.
- Adequately heated to maintain effectiveness.

4.6.4 BOP controls

Contents This section contains information on the requirements for BOP controls, including:

- Primary controls
- Secondary controls
- Master hydraulic control manifold
- Hydraulic BOP control hoses

Primary controls Each BOP component must have a separate control located at the remote position (typically the accumulator). These controls must be:

- Capable of opening and closing each BOP component.
- Readily accessible and housed to ensure that they can be protected from the well in the event of an uncontrolled flow.
- Correctly identified and show function operations (open and close).
- Equipped with an accurate gauge indicating the accumulator system pressure.

Secondary controls Each BOP component must have a separate control located near the driller's position on the rig floor. These controls must be:

- Capable of opening and closing each BOP component.
- Readily accessible, correctly identified, and show function operations (open and close).
- Equipped with an accurate gauge indicating the accumulator system pressure.

Master hydraulic control manifold The master hydraulic control manifold must be located at the remote position (typically the accumulator) for all wells.

Hydraulic BOP control hoses Non-steel hydraulic BOP control hoses without fire sheathing must be located at least 7 meters from the well.

4.7 Bleed-off / kill system

Contents	<p>This section contains requirements for:</p> <ul style="list-style-type: none">• Circulation manifolds• Rig tanks and fluid volume monitoring systems• Tubing pressure gauge assemblies• Bleed-off / kill lines• Pressure vessels and pressure vessel inlet lines• Flare lines
4.7.1 Circulation manifolds	
Contents	<p>This section contains the requirements for circulation manifolds:</p> <ul style="list-style-type: none">• Components• Installation• Pressure gauges• Pressure relief
Components	<p>A circulation manifold consists of high-pressure pipes, fittings, flanges, valves, pressure gauges, and manually operated adjustable valves.</p>
Installation	<p>The circulation manifold must:</p> <ul style="list-style-type: none">• Be outside the substructure and readily accessible.• Be labelled to identify the fully open and fully closed positions for all valves.• Always be fully operable with all valve handles in place. <p>The circulation manifold may include in-line glycol recovery drainage ports if they do not compromise system integrity or function.</p>
Pressure gauges	<p>An accurate circulation manifold pressure gauge must be installed, or readily accessible for installation, at:</p> <ul style="list-style-type: none">• The circulation manifold, regardless of which valve line is in use; and• The remote valve control location (if in use or required). <p>All gauges must:</p> <ul style="list-style-type: none">• Meet the pressure rating of the required BOP system.• Have maximum readable increments of 500 kPa.• Have isolation valves.
Pressure relief	<p>A pressure relief system must be installed on the rig pump discharge to prevent the rig pump from over pressuring. The maximum pressure setting of the pressure relief system must not exceed the calculated or anticipated working pressure or exceed the pressure rating of the weakest component in the circulating system.</p>

Service Rig Operation Safety Guidelines and Interpretation Notes

4.7.2 Rig tanks and fluid volume monitoring systems

Requirements	<p>All wells being serviced must have rig tanks with an appropriate rig tank fluid volume monitoring system.</p> <p>The fluid volume monitoring system must be in service when the rig tank is in use.</p> <p>The fluid volume monitoring system must be able to:</p> <ul style="list-style-type: none">• Measure an imbalance in the volume of fluids entering and returning from the well.• Measure a change in total tank volume of less than 2m³.
---------------------	---

4.7.3 Tubing pressure gauge assemblies

Requirements	<p>Tubing pressure gauge assemblies must:</p> <ul style="list-style-type: none">• Have an accurate pressure gauge and other necessary equipment installed or readily accessible.• Be assembled by the rig crew as part of the BOP drill if the equipment is not already installed.• Be readable from the rig pump control station while operating the valve from the circulation manifold.• Have isolation valves.
---------------------	---

4.7.4 Bleed-off/kill lines

Contents	<p>This section contains the requirements for the bleed-off/kill lines connecting the BOP stack to the circulation manifold:</p> <ul style="list-style-type: none">• Valves• Installation• Flexible hoses• Operation• Wells with a total vertical depth (TVD) > 3,600 meters
Valves	<p>Bleed-off/kill lines include both hydraulically operated and manual valves.</p>
Installation	<p>Bleed-off/kill lines must:</p> <ul style="list-style-type: none">• Always be connected to the working spool and circulation manifold.• Have flange or clamp type connectors pressure tested at the connection whenever a connection is loosened or disassembled after initial pressure test(s).• Always have the valve handles in place for all manual valves in the primary and secondary bleed-off/kill lines.• Directly connect the innermost valve to the working spool or ported ram assembly. Crossover flanges between the working spool and the innermost manual valve are permitted.

Service Rig Operation Safety Guidelines and Interpretation Notes

- Be properly supported to prevent stresses on connecting valves and fittings.
- Be secured at every connection point and at no more than 10-meter intervals.

Bleed-off/kill lines may include piping extensions or fluid turns between the manual valves if:

- The innermost valve is in the closed position and the secondary bleed-off line (with two manual valves) is in use.
- All fluid turns in the bleed-off line are made with right angle (90°) connections constructed of tees and crosses blocked on fluid turns.

Prohibition: Piping extensions or fluid turns are not permitted between the working spool and the innermost valve.

Flexible hoses

Flexible hoses may only be used for directional changes in the bleed-off lines downstream of the manual valves. They must:

- Have factory installed connections.
- Maintain their original shape and not contain bends with a radius less than the manufacturer's specified minimum bending radius.
- Be supported and protected from mechanical damage.
- Be secured (if it is a non-flange hose).
- Have competent fire sheathing to withstand a minimum of 700°C for 5 minutes flame temperature at a maximum working pressure without failure, if used within 7 meters of a well.

Operations

During normal operations:

- The valve on the primary bleed-off line must be closed and the secondary valve must be in the open position.
- If the secondary bleed-off line is required or in use, only one of the manual valves on the secondary bleed-off line can be in the closed position, provided that both are flanged together.

TVD > 3,600 meters

For wells with a TVD > 3,600 meters, there must be a separate bleed-off line from each working spool connected to each separate manifold wing to provide complete redundancy from the BOP stack through to the manifold.

Service Rig Operation Safety Guidelines and Interpretation Notes

4.7.5 Pressure vessels and pressure vessel inlet lines

Contents

This section contains the requirements for:

- Pressure vessels
- Pressure vessel inlet lines

Pressure vessel requirements

Pressure vessels must:

- Be built of steel to ensure fluid containment during prolonged exposure to extreme heat. Structural integrity of the pressure tank must be maintained.
- Include an impingement plate to resist erosion from high-velocity gas, liquids, and solids on the wall directly opposite all flare lines connected to the tank.
- Capable of handling anticipated pressures encountered during well intervention.
- Always have a minimum 50.8 mm liquid loading steel line connected to draw fluids from the tank. The connection point of the loading line must extend at least 9 meters from the pressure tank.

Pressure vessel inlet lines

Prohibition: No valves or other mechanical restrictions are permitted in the pressure vessel inlet line.

4.7.6 Flare lines

Contents

This section contains the requirements for flare lines from the circulation manifold to the pressure tank:

- Installation
- Flexible hoses
- Wells with a TVD > 3,600 meters

Installation

Flare lines must be:

- Always connected to the manifold.
- Laid in a straight line from the manifold to the pressure tank. If required to accommodate equipment, flare lines may contain directional changes if they are made with right angle (90°) connections constructed of tees and crosses blocked on fluid turns.
- Connected using flanges, threaded fittings, or hammer unions. If a pressure tank is in use, interconnecting cable mechanisms or sling straps must be used to secure the connections.
- Secured:
 - At every connection point.
 - At no more than 10-meter intervals
 - With the end of the line secured as close as possible to the pressure tank.
- Self-draining or incorporating a means to drain fluid from the line.

Service Rig Operation Safety Guidelines and Interpretation Notes

Flexible hoses	Flexible hoses may be used as flare lines or emergency flare lines if they: <ul style="list-style-type: none">• Have factory installed connections.• Maintain their original shape and do not contain bends with a radius less than the manufacturer's specified minimum bending radius.• Are supported and protected from mechanical damage.• Are secured (if it is a non-flange hose).• Have competent fire sheathing to withstand a minimum of 700°C flame temperature at a maximum working pressure without failure, if used within 7 meters of a well.
TVD > 3,600 meters	<p>Prohibition: Flexible hoses are not permitted within 9 meters of the pressure tank.</p> <p>For wells with a TVD > 3,600 meters, there must be at least two flare lines installed.</p>

5 Other Equipment on Site

Contents

This section contains requirements for other equipment on the well site:

- Electrical and fired heating equipment.
- Equipment with internal combustion engines.

Service Rig Operation Safety Guidelines and Interpretation Notes

5.1 Electrical and fired heating equipment

Contents	<p>This section describes limitations on the use of electrical and fired heating equipment in a hazardous location, including:</p> <ul style="list-style-type: none">• Electrical appliances or devices• Electrical motors or generators• Flame-type equipment
Definition: hazardous location	<p>A hazardous location is the area within 25 meters of the wellbore or any structure where combustible materials or gasses can collect.</p>
Electrical appliances or devices	<p>Prohibition: Electrical appliances or devices that are a potential source of ignition are not permitted in a hazardous location.</p> <p>If the operator must use electrical appliances or devices that are a potential source of ignition in a hazardous location, the operator must:</p> <ul style="list-style-type: none">• Confirm that the electrical appliance or device is specifically approved and suitable for its intended application.• Assess on-site safety.• Develop safety procedures for the operation.• Review the safety assessment and procedures with the crew.• Document the assessment and procedures in the tour report before the operation is conducted. <p>Electrical appliance or devices that are a potential source of ignition in a hazardous location must adhere to the requirements of:</p> <ul style="list-style-type: none">• The most current version of Canadian Electrical Code CSAC22.1.• The most current version of the <u>Oil and Gas Installations Regulations</u> (OGIR).• CAOEC Recommended Practice 8.0.• API Recommended Practice 500. <p>If a conflict exists between the Canadian Electrical Code and the OGIR, operators should contact the Chief Safety Officer to discuss how to proceed under section 54 of the <i>Oil and Gas Operations Act</i>.</p>
Electrical motors or generators	<p>Prohibition: Electrical motors or generators that produce arcing during operation may not be placed or operated in a hazardous location unless the motor or generator is purged with an air intake:</p> <ul style="list-style-type: none">• Located outside the hazardous location, and• In compliance with the Canadian Electrical Code CSAC22.1.
Flame-type equipment	<p>Prohibition: Flame-type equipment is not permitted in a hazardous location.</p>

Service Rig Operation Safety Guidelines and Interpretation Notes

If the operator must use flame-type equipment that is a potential source of ignition in a hazardous location, the operator must:

- Locate the intakes, exhausts, and fire box of a furnace or fired heater outside the hazardous location.
- Ensure surfaces within the hazardous location which are exposed to the atmosphere operate below the temperature that would ignite a flammable substance present in the hazardous location
- Ensure air intake and exhaust discharge are equipped with a flame arresting device or are located outside the hazardous location.

Definition: flame-type equipment

Flame-type equipment is any equipment using an open flame. Examples include space heaters, torches, heated process vessels, boilers, electric arc or open-flame welders, stoves, furnaces, and pilot lights.

5.2 Equipment with internal combustion engines

Contents	<p>This section contains information on the requirements for equipment with internal combustion engines in a hazardous location, including:</p> <ul style="list-style-type: none">• Engine shutoff devices• Testing requirements for shutoff devices• Vehicles without shutoff devices• Exhaust pipe requirements• Diesel engine requirements
Definition: hazardous location	<p>A hazardous location is the area within 25 meters of the wellbore or any structure where combustible materials or gasses can collect.</p>
Engine shutoff devices	<p>The acceptable shutoff devices for internal combustion engines operating in a hazardous location are:</p> <ul style="list-style-type: none">• A manual air intake shutoff device readily accessible from the driller's position.• A system capable of injecting an inert gas into the engine's cylinders, equipped with a remote control readily accessible from the driller's position.• Another device approved by the Regulator.
Testing requirements for shutoff devices	<p>All internal combustion engine shutoff devices must be tested:</p> <ul style="list-style-type: none">• Before well servicing operations begin.• Weekly after operations have begun. <p>Shutoff device testing results must be recorded in the daily reports and logbook.</p>
Vehicles without shutoff devices	<p>Prohibition: Internal combustion engines not equipped with engine shutoff devices may not operate in a hazardous location.</p> <p>If the operator must use internal combustion engines not equipped with engine shutoff devices in a hazardous location, the operator must:</p> <ul style="list-style-type: none">• Confirm that the equipment is specifically approved and suitable for its intended application.• Assess on-site safety.• Develop safety procedures for the operation.• Review the safety assessment and procedures with the crew.• Document the assessment and procedures in the tour report before the operation is conducted.
Exhaust pipe requirements	<p>An exhaust pipe from an internal combustion engine in a hazardous location must be constructed so that:</p> <ul style="list-style-type: none">• Flames are prevented from emerging along its length or at its end.

Service Rig Operation Safety Guidelines and Interpretation Notes

- The end of the exhaust pipe is more than 6 meters away from the vertical centreline (projected upward) of the well.
- The end of the exhaust pipe is not directed toward the well.

Diesel engine requirements

In addition to the other requirements of this section, air intakes for diesel engines must be located at least 25 meters from the well.

6 Well Site Spacing

Contents

This section provides information on:

- Exemptions from the minimum spacing requirements
- Minimum spacing requirements for well site equipment:
 - Table
 - Diagram

Exemptions

If it is not possible to meet these minimum spacing requirements due to site conditions, the operator must:

- Inform the Chief Safety Officer as soon as possible.
- Submit a written request for exemption including a proposed site spacing diagram and rationale.

Minimum spacing requirements table

The following table shows the minimum spacing requirements for well site equipment.

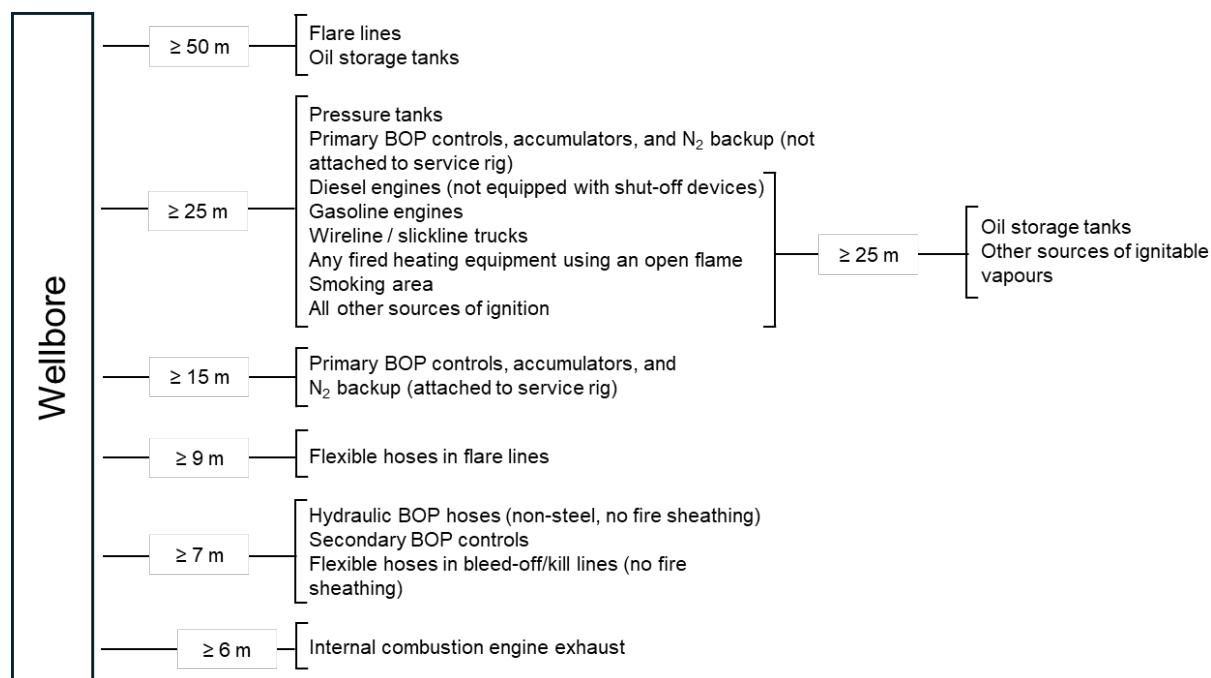
Equipment	Minimum Spacing Requirements
Internal combustion engine exhaust	Locate at least 6 meters from the vertical centreline of the wellbore.
Hydraulic BOP hoses (non-steel, without fire sheathing)	Locate at least 7 meters from the wellbore.
Secondary BOP controls	Locate at least 7 meters from the wellbore.
Flexible hoses in bleed-off/kill lines (no fire sheathing)	Locate at least 7 meters from the wellbore.
Flexible hoses in flare lines	Locate at least 9 meters from the pressure tank.
Primary BOP controls, accumulators, and N ₂ backup	Locate at least 15 meters from the wellbore if attached to the service rig. If not attached to the service rig, locate at least 25 meters from the wellbore.
Pressure tanks	Locate at least 25 meters from the wellbore.
Diesel engines (not equipped with shut-off devices) and gasoline engines	Locate at least 25 meters from the wellbore, oil storage tanks, or other sources of ignitable vapours.

Service Rig Operation Safety Guidelines and Interpretation Notes

Equipment	Minimum Spacing Requirements
Wireline / slickline trucks	Locate at least 25 meters from the wellbore, oil storage tanks, or other sources of ignitable vapours.
Any fired heating equipment using an open flame	Locate at least 25 meters from the wellbore, oil storage tanks, or other sources of ignitable vapours.
Smoking area	Locate at least 25 meters from the wellbore, oil storage tanks, or other sources of ignitable vapours.
Flare lines	Terminate at least 50 meters from the wellbore.
Oil storage tanks	Locate at least 50 meters from the wellbore

Minimum spacing requirements diagram

The following diagram shows the minimum spacing requirements for well site equipment.



7 Specific Operations

Contents This section contains requirements for the following specific operations:

- Overbalanced milling
- Underbalanced milling and shallow wellbore plugs

7.1 Overbalanced milling

Contents	<p>This section provides information on:</p> <ul style="list-style-type: none">• Controlling formation pressures• Mandatory on-site documentation for overbalanced operations• Tripping during overbalanced operations
Definition: overbalanced milling	<p>Overbalanced milling occurs when the hydrostatic head of a workover fluid above the plug, together with the weight of the working string, is intentionally designed so that the downward forces acting on a plug being milled are greater than the upward forces from the potential formation pressure below acting on the plug. Overbalanced milling may occur naturally or be induced.</p>
Controlling formation pressures	<p>The operator must ensure sufficient workover fluid density is maintained to control formation pressures throughout the well operation unless the formations have been abandoned.</p>
Mandatory on-site documentation	<p>The following information must be available on-site during overbalanced operations:</p> <ul style="list-style-type: none">• Procedures and crew responsibilities during overbalanced operations• Rig pump specifications• Current well data required to control a kick
	<p>Calculations and formulas (for tubing volume, hydrostatic weight of kill fluid, casing and tubular capacities and displacements, etc.) must be as described in Acronyms, Formulas and Well Control Forms issued by Enform (now Energy Safety Canada).</p>
Tripping	<p>Before tripping the work string from the well during overbalanced operations, the operator must:</p> <ul style="list-style-type: none">• Maintain sufficient workover fluid density to overbalance the expected formation pressures so that formation fluids do not enter the wellbore.• Conduct a bottom-up circulation or pump a weighted tripping pill.
Definition: tripping	<p>Tripping is the process of adding or removing the work string, bottomhole assembly, and any other tools used to make the drill bit turn at the bottom of the wellbore (SLB Energy Glossary).</p>

7.2 Underbalanced milling and shallow wellbore plugs

Contents	This section provides information on:
	<ul style="list-style-type: none">• Mandatory disclosure• Compliance with Industry Recommended Practices (IRPs)• Using a snubbing unit during underbalanced milling operations• Using a coiled tubing rig during underbalanced milling operations• Pre-operation hazard assessment• Reporting
Definition: underbalanced milling	Underbalanced milling occurs when the hydrostatic head of a workover fluid is intentionally designed to be lower than the pressure of the formation being drilled. Underbalanced milling may occur naturally or be induced.
Definition: shallow wellbore plug	A shallow wellbore plug is any wellbore plug that does not allow the wellbore to be safely killed by overbalancing the plug, including a margin of safety, with weighted fluid and the working string weight. Shallow wellbore plugs result in an underbalanced milling operation.
Mandatory disclosure	Operators must disclose underbalanced milling operations to OROGO as soon as possible, either: <ul style="list-style-type: none">• As part of the well approval application; or• Immediately after encountered during well operations. The presence of a shallow wellbore plug, or suspected presence of a shallow wellbore plug based on historical records, must be disclosed in all well approval applications. The well servicing program must assume reservoir pressure is present below the plug.
Compliance with IRPs	Underbalanced milling operations must comply with: <ul style="list-style-type: none">• The blowout prevention system requirements in Energy Safety Canada's <u>IRP 22: Returns Management Drilling, Managed Pressure Drilling, and Underbalanced Drilling Operations</u> or <u>IRP 15: Snubbing Operations</u>.• The snubbing, tripping, and stripping procedures described in IRP 15, IRP 22, and these Guidelines.
Snubbing units	A snubbing unit must be installed before underbalanced milling operations begin. It must remain in place until: <ul style="list-style-type: none">• Pressures are equalized; or• The wellbore has been killed with weighted fluid.
Coiled tubing units	Coiled tubing units may be used as an alternative to snubbing units if they are rated for the maximum anticipated well bore pressure and if they are used in the manner described above.

Service Rig Operation Safety Guidelines and Interpretation Notes

Pre-operation hazard assessment	Before an underbalanced milling operation, the operator must conduct a hazard assessment. The assessment must include: <ul style="list-style-type: none">• Identifying hazards and mitigations if pressure is found.• Reviewing BOP and evacuation procedures.• Inspecting and securing the rig, hoses, and other equipment that may encounter pressures from the wellbore.• Identifying danger zones and ensuring only essential staff are present and safety positioned to avoid the identified potential hazards in the immediate work area during milling operations.• Placing the medic on standby and ensuring they are present for during the hazard assessment and all operations.
Reporting	<p>The pre-operation hazard assessment must be recorded in the tour sheets and submitted to OROGO at least one hour before the underbalanced milling operation begins.</p> <p>Within one hour of completing the underbalanced milling operation, a summary of operations must be submitted to OROGO.</p>

8 Administrative Controls

Contents

This section contains information on the administrative controls that must be in place during service rig operations, including:

- Well site supervision
- Rig crew certification
- BOP drills
- Operator and contractor inspections
- On-site documentation for well control

Service Rig Operation Safety Guidelines and Interpretation Notes

8.1 Well site supervision

Contents	This section contains information on the requirements for well site supervision: <ul style="list-style-type: none">• By the operator• By the rig manager• During tripping operations• During well control situations
Definition: operator	The operator is the company named on the operations authorization issued by the Regulator for the activity.
Operator supervision	The operator must provide an on-site representative responsible for supervising the well operations. This representative: <ul style="list-style-type: none">• Must be on-site during operations. If the representative is making an off-site trip, they must be:<ul style="list-style-type: none">○ Available within two hours' travelling time and○ Always reachable by radio, text, or phone.• Cannot be the rig manager.• Cannot supervise multiple servicing operations at the same time.
Rig manager	The rig manager is responsible for supervision of the service rig. The rig manager: <ul style="list-style-type: none">• Must be on-site unless a relief rig manager is on site.• Cannot supervise multiple servicing operations at the same time.
Supervision of tripping operations	The operator representative or the rig manager must be on site during tripping operations when the wellbore is open to the hydrocarbon bearing zone(s).
Supervision of well control situations	The operator representative or the rig manager must be on site during well control situations.

Service Rig Operation Safety Guidelines and Interpretation Notes

8.2 Rig crew certification

Contents	This section describes required rig crew certifications:										
	<ul style="list-style-type: none">• Mandatory well control certificates• Mandatory health and safety certificates• Characteristics of valid certificates• Consequences of unavailable certificates										
Mandatory well control certificates	The following well control certificates, issued by Energy Safety Canada , are mandatory:										
	<table border="1"><thead><tr><th>Individual</th><th>Minimum Mandatory Certificate</th></tr></thead><tbody><tr><td>Operator representative</td><td>Well servicing blowout prevention</td></tr><tr><td>Rig manager/tool push</td><td>Well servicing blowout prevention</td></tr><tr><td>Driller</td><td>Well servicing blowout prevention</td></tr><tr><td>Coiled tubing unit operator</td><td>Coiled tubing well servicing blowout prevention</td></tr></tbody></table>	Individual	Minimum Mandatory Certificate	Operator representative	Well servicing blowout prevention	Rig manager/tool push	Well servicing blowout prevention	Driller	Well servicing blowout prevention	Coiled tubing unit operator	Coiled tubing well servicing blowout prevention
Individual	Minimum Mandatory Certificate										
Operator representative	Well servicing blowout prevention										
Rig manager/tool push	Well servicing blowout prevention										
Driller	Well servicing blowout prevention										
Coiled tubing unit operator	Coiled tubing well servicing blowout prevention										
Mandatory health and safety certificates	The following health and safety certificates are mandatory:										
	<ul style="list-style-type: none">• First aid attendant certificates in compliance with Schedule H of the <i>Occupational Health and Safety Regulations R-039-2015</i> for:<ul style="list-style-type: none">○ Intermediate first aid.○ Advanced first aid.○ Emergency medical technician.• H₂S Alive (issued by Energy Safety Canada) for all onsite personnel when the presence of H₂S is unknown, anticipated or identified.• WHMIS for Workers for all onsite personnel.										
Characteristics of valid certificates	Valid certificates are: <ul style="list-style-type: none">• Not expired (including temporary cards).• Available for review by OROGO inspectors upon request.										
Consequences of unavailable certificates	If the mandatory certificates are not available for review by OROGO inspectors upon request, operations may be suspended (if safe to do so) until certificates are provided or qualified individuals are on site.										

Service Rig Operation Safety Guidelines and Interpretation Notes

8.3 BOP drills

Contents	This section contains the requirements for BOP drills, including:
	<ul style="list-style-type: none">• Frequency• Scenarios• Procedure• Recording results
Frequency	BOP drills must be conducted:
	<ul style="list-style-type: none">• Once rig is stood up and BOP installation is complete.• When a new crew comes on site after initial BOP installation.• Every seven calendar days (if on the same well).
Scenarios	BOP drill scenarios should rotate through all kick scenarios possible during the operation, for example:
	<ul style="list-style-type: none">• Drilling / cleaning to bottom / circulating• Tripping work string• Work string is out of the well• Tripping sucker rods
Procedure	BOP drills must be completed as described in the Energy Safety Canada Well Service Blowout Prevention course.
Recording results	All BOP drills must be recorded in the tour sheets and daily reports.

Service Rig Operation Safety Guidelines and Interpretation Notes

8.4 Operator and contractor inspections

Contents	This section provides information on mandatory inspections by operators and contractors, including: <ul style="list-style-type: none">• Daily inspections• Detailed inspections• Flare line inspections• Recording inspections• Reporting non-compliance
Definition: operator	The operator is the company named on the operations authorization issued by the Regulator for the activity.
Daily inspections	Daily inspections: <ul style="list-style-type: none">• Are walk-arounds of the service rig to identify any non-compliances with these Guidelines.• Must be conducted in conjunction with the daily three component test referenced in section 4.2.
Detailed inspections	Detailed inspections must review all well control and other equipment on site for compliance with these Guidelines. Detailed inspections must be conducted: <ul style="list-style-type: none">• Before entering the well with the work string.• At least weekly during the operation.
Flare line inspections	Flare lines must be inspected: <ul style="list-style-type: none">• Before assembly: A visual inspection of all connections between the circulation manifold and the pressure tank or degasser.• After assembly: An inspection must be conducted to ensure proper make-up.
Recording inspections	All inspections must be recorded in the tour sheets.
Reporting non-compliance	Any non-compliance (corrected or not) must be reported to OROGO in the daily report.

8.5 Onsite documentation for well control

Contents This section describes the requirements for onsite documentation for well control, including:

- Blowout prevention and well control procedures
- Maximum operating pressure
- Bottom hole pressure
- Wellbore diagram

Blowout prevention and well control procedures Blowout prevention and well control procedures must be posted in the doghouse.

These procedures must include:

- Flow check procedures
- Kick warning signs
- Crew positions during well control situations
- Well shut-in procedures
- Well control methods

Maximum operating pressure The maximum operating pressure must be posted at the circulation manifold and at the remote valve control location (where available).

Bottom hole pressure Bottom hole pressures must be calculated prior to the start of operations as described in the [Energy Safety Canada](#) Well Service Blowout Prevention course.

Bottom hole pressures must be posted in the doghouse and the consultant's trailer.

Wellbore diagram The wellbore diagram must be posted in the doghouse.

The wellbore diagram must be reviewed by appropriate on-site personnel before beginning well service operations.

The wellbore diagram must include:

- Geological formation tops
- Cement tops
- Casing and liner description, location, and depth
- Plugs, retainers, and packer description and location
- Location of perforations
- Type of wellbore fluid
- Presence of H₂S or acid gas
- Reservoir pressure

9 Regulator's Approval

These *Service Rig Operation Safety Guidelines and Interpretation Notes* are issued under section 18 of the *Oil and Gas Operations Act* effective March 31, 2025.



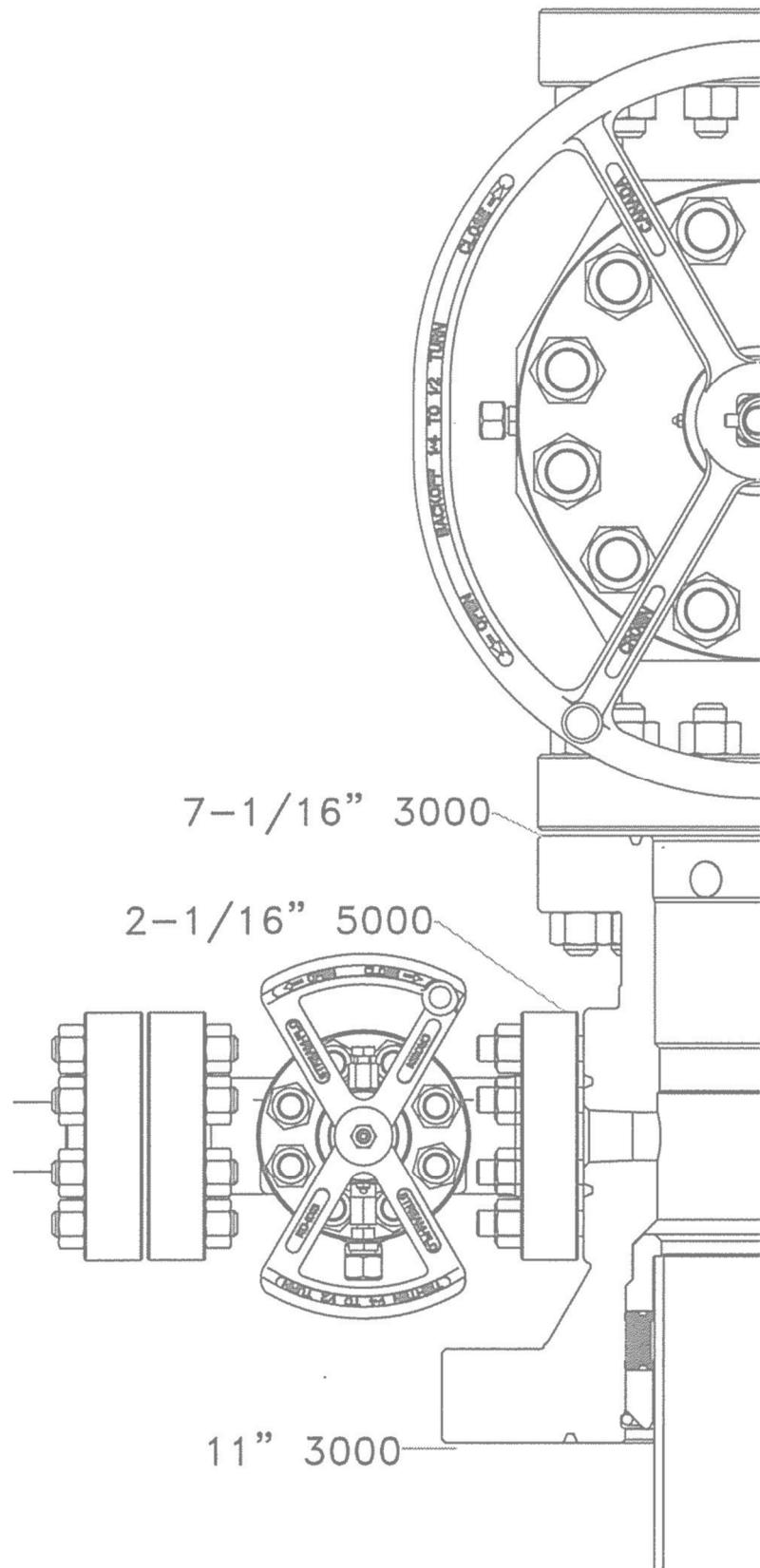
Pauline de Jong
Regulator

OROGO

NWT OFFICE OF THE REGULATOR OF OIL AND GAS OPERATIONS

BOROPG

BUREAU DE L'ORGANISME DE RÉGLEMENTATION DES OPERATIONS PÉTROLIÈRES ET GAZIÈRES DES N.-O.



(867) 767-9097

orogo@gov.nt.ca

www.orogo.gov.nt.ca