

IRP 3.3 COMPLETIONS & WELL SERVICING

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Note to Reviewers:

This is third chapter of six in IRP 3.

This is the second industry review for this chapter. Modifications based on comments from the first industry review have been incorporated in consultation with the original Completions and Well Servicing Working Group.

Modifications are noted as follows:

- New content is green
- Deleted content has a strikethrough
- Appendix A and B drawings have been modified for clarification in accordance with regulation.



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3.3. COMPLETIONS & WELL SERVICING

3.3.1 INTRODUCTION

Completions and well servicing reviews concerns specific to in situ heavy oil operations and includes those situations common to the heavy oil industry with a primary focus on worker safety.

The content presented here is intended for production engineers, completions superintendents, wellsite supervisors, and those in planning from an integrated approach.

This chapter emphasizes key regulations in several REG statements. IRP statements are phrased with both “shall” and “should” throughout the chapter. Appendices A and B illustrate spacing diagrams that are also provided in a larger format for reproduction in the Doghouse package available on the IRP 3 landing page.

Central topics covered in completions and well servicing include:

- Service rig operations for primary and secondary wells
- Continuous rod rigs
- Coiled tubing
- Wireline
- Snubbing units
- Flush-by units

3.3.1.1 Definitions

Following are a collection of key definitions relevant to completions and well servicing. A complete glossary with terms used across the entire IRP is available in the Glossary at the back of this document.

Heavy Kill

Heavy kill occurs when the volume of kill fluid has sufficient density and composition to successfully kill the well.

Keyseat

Keyseat refers to a small diameter channel worn into the side of tubing or casing string.

Ovality

The degree of ovality refers to the difference in the ratio of minimum ID to maximum ID.

Primary Recovery Well (Class IIA)

According to ID 91-3, a primary recovery well has a reservoir sandface pressure equal to or less than the hydrostatic pressure that would be exerted at the sandface if the well were filled with formation fluids.

Secondary Recovery Well (Class IIA)

According to ID 91-3, a secondary recovery well has a reservoir sandface pressure greater than the hydrostatic pressure that would be exerted at the sandface if the well were filled with formation fluids. It occurs by virtue of injection into the formation of fluid(s) other than water at ambient temperatures. This includes all wells that are part of an active Enhanced Oil Recovery (EOR) project, approved by the ERCB and any offset wells within 1000 m of an EOR well.

Sandface

The sandface refers to the physical interface between the formation and the wellbore. The diameter of the wellbore at the sandface is one of the dimensions used in production models to assess potential productivity.

3.3.2 COMPLETIONS DESIGN

Completions design needs to consider the production scheme intended for the well. Equally, production operations need to assess the completions design if modifications to the original production scheme occur at any time through the life cycle of the well (see 3.5 Production Operations).

IRP Completions design should consider the intended production scheme in the final design and Operators shall document the final completions design.

IRP An engineering assessment should be completed when modifications to the original completion design are required.

3.3.3 PRIMARY WELL SERVICING

Primary well servicing refers to well servicing that does not involve enhanced oil recovery (EOR) or secondary recovery.

3.3.3.1 Offset production

It is important to review offset production data and history to identify potential problems during well servicing operations. From the perspective of in situ heavy oil operations, wells can become sour after a short time on production (see 3.1.2.3 Surface Casing Vent Flow and Gas Migration and 3.5.5 Surface Casing Vent and Gas Migration Monitoring).

To reduce potential problems consider the following data sources:

- area zonal communication,
- cumulative production of offset wells,
- BHP,
- H₂S content, and
- use of EOR techniques or stimulation methods.

IRP Any well within a 1000 m of a high pressure CSS well, or within 300 m of a SAGD well, shall follow thermal procedures described in [3.3.4 Secondary Well Servicing](#) below.

Note. If after two years no steaming has been carried out within 1000 m of a well, the well may be considered primary with regulatory approval. Approval may be granted on the basis of a current reservoir pressure and temperature survey.

A thorough individual well history is important to assess the potential for well servicing problems. Well history data gathering should consider, but not be limited to, the following:

- data on cumulative and current offset well production
- data on BHP, temperature, H₂S content, casing failures, surface casing vent flow (SCVF), gas migration (GM), sand issues
- data on EOR techniques (e.g., steam, fireflood, O₂ injections, CO₂ injection, propane floods, polymer floods)

3.3.3.2 Primary Completions Planning

The following planning considerations are pertinent to primary completions.

- Review BHP casing, wellhead, sand content, fluid viscosity, fluid density, and regulatory requirements.
- Ensure wellhead design includes full bore access and tool access to casing weights.
- Prior to completion, ensure surface casing isolation from production casing and install a surface casing vent assembly.
(see REG statement below and 3.5.5 Surface Casing Vent and Gas Migration Monitoring)
- Install valves on all standing cased wells.
- Establish baseline gas migration data prior to completion (see 3.5.5 Surface Casing Vent and Gas Migration Monitoring).
- Ensure communication and synergy with drilling for conditions and final design of the well (e.g., cement, deviations, doglegs, trouble spots, etc.) Refer to 3.1.2 Operational Integrity.
- ~~• Design well pads and patterns to maximize service and completion work.~~
- Design well pads and patterns that efficiently accommodate service and completion work (see 3.1.1.2 Multi-Operational Pad Planning).

REG Well completion design must accommodate a surface casing vent (SCV) assembly in accordance with jurisdictional regulations.

REG In Saskatchewan, surface casing bowls can only be removed (without prior approval) in Township 44-54 inclusive, and only if the production casing is cemented to surface with no fallback and the gas migration and SCVF tests are negative.

Note. All horizontal wells and any wells outside the area described

above require written approval from the Ministry of Energy & Resources Regional office to have surface casing bowls removed.

To prepare a well for primary production, it is important to follow established procedures during wellhead installation. For in situ heavy oil operations, conduct wellhead installation procedures with particular attention to:

- back welding,
- pressure testing,
- availability of mill certifications, and
- corresponding heat numbers.

It is equally important to ensure equipment is properly rated for pressure, temperature, and the possibility of future H₂S (see 3.1.2.3 Surface Casing Vent Flow and Gas Migration).

For detailed guidance on installation procedures refer to IRP 5.2.3 Wellhead Installation.

REG ~~In Saskatchewan, surface casing bowls can only be removed in Township 44-54 inclusive, and only if the production casing is cemented to surface with no fallback and the gas migration and SCVF tests are negative.~~

IRP Wellhead designs should accommodate existing and anticipated future operating parameters (e.g., workover, stimulation, EOR). Refer to IRP 5: Minimum Wellhead Requirements and in this document 3.4.3 Wellhead Design.

It is important to prepare completions plans that include considerations for abandonment such as:

- Ensure the wellhead design accommodates future abandonment.
- Evaluate lower cased zones for abandonment prior to completion.
- Consider cased hole abandoning lower zones on initial completion, if sump is excessive below the target zone.

3.3.3.3 Primary Well Completions and Workovers

REG All in situ heavy oil primary well completions and workovers must comply with relevant jurisdictional regulations.

Following is a list of the key regulatory documents:

- [Directive 033: Well Servicing and Completions Operations - Interim Requirement Regarding the Potential for Explosive Mixtures and Ignition in Wells](#)

- [*Directive 037: Service Rig Inspection Manual*](#)
- [*ID 91-3: Heavy Oil/Oil Sands Operations*](#)
- [*IRP Volume 7: Standards for Wellsite Supervision of Drilling, Completion and Workovers*](#).
- Saskatchewan's [*Oil and Gas Conservation Regulations, 1985*](#)
- [*Saskatchewan Upstream Industry Storage Standards*](#)

Additionally, completions and workovers should consider the following:

- spacing limitations due to existing production facilities (see [Appendix A: Well Servicing Equipment Minimum Spacing](#) and [Appendix B: Associated Well Servicing Equipment Minimum Spacing: Class IIA](#). For a combined diagram of spacing requirements for service rigs, drilling rigs and existing wells see: 3.1 Integrated Planning, Appendix A: Minimum Spacing Requirements for Multi-Operational Pads);
- accommodations for well type (e.g., horizontal, directional, slant, vertical, and well service classification);
- if applicable, ensure an Emergency Response Plan (ERP) is in place and in accordance with jurisdictional regulations;
- if applicable, ensure procedures are in place to address venting of odorous compounds and to control noise during well servicing operations in accordance with jurisdictional regulations; and
- waste management in accordance with jurisdictional regulations (see 3.1.1.6 Waste Management).

3.3.3.4 Primary BOP and Well Control Requirements

All primary BOP configurations are considered Class IIA in accordance with [ID 91-3 Heavy Oil/Oil Sands Operations](#).¹ Class IIA Primary refers to a well having a sandface reservoir pressure equal to or less than the hydrostatic pressure that would be exerted at the sandface if the well were filled with formation fluids.

REG BOP components on a Class IIA primary well must be tested to the pressures specified in [Section 8.147](#) of the [Oil and Gas Conservation Regulations](#). A 10-minute test must be conducted prior to servicing the first well of a program (i.e., change of Operator), and thereafter, within 30 calendar days.

Note. A kill line is not required on a Class IIA BOP.

¹ Since ID 91-03 was originally published in 1991, it refers to 'Class IIA'. All current ERCB documentation now has dropped the 'A' and refers to 'Class II' only.

REG **In Saskatchewan BOP components must comply with the Saskatchewan Oil and Gas Conservation Regulations (1985).**

General primary well control considerations follow.

- Determine if servicing BOPs requires full bore access to production casing. When moving tubing, full access to the wellbore is recommended at all times.
- Consider anticipated BHP.
- Be aware of the type and volume of kill fluid required.
- Follow established kill procedures.
- Determine operations to be carried out (e.g., coil tubing [see [IRP Vol. 21 - Coiled Tubing Operations](#)], wireline, continuous rod, flush-by operations, etc.).
- Determine tools to be used that would affect BOP configuration/regulation.
- Ensure appropriate cutters are on the floor for capillary tubes and Electric Submersible Pump (ESP) power cables.

Tubing strings too small for the existing pipe ram size(s) may be pulled either with an annular BOP and variable type ram, or alternatively an annular BOP and rod ratigans.

3.3.3.5 Primary Well Stimulation

Primary well stimulation includes four key considerations: spacing, stimulus operations, foaming, and swabbing.

a. Spacing

The density of fluid being pumped may affect equipment spacing requirements. Refer to [Appendix A: Well Servicing Equipment Minimum Spacing: Class IIA](#) and [Appendix B: Associated Well Servicing Equipment Minimum Spacing: Class IIA](#) for spacing specifications.

Note. Density under 920 kg/m³ changes well treatment considerations and spacing requirements.

For solvent injection operations, refer to [IRP Volume 8: Pumping of Flammable Fluids](#).

REG **All stabilized foam cleanout operations must comply to ERCB Class IIA equipment spacing regulations.**

REG **In Saskatchewan all stabilized foam cleanout operations must comply to Saskatchewan Oil and Gas Conservation Regulations**

(1985) and the PDB ENV 13 – S-01 Saskatchewan Upstream Petroleum Industry Storage Standards. Additionally, discussion with Saskatchewan OHS may also be required.

b. Stimulus Operations

REG All stimulus operations must follow established OHS procedures.

REG Stimulus operations (e.g., acidizing, fracturing, foam cleanout) must be in accordance with Directive 033: Well Servicing and Completions Operations - Interim Requirement Regarding the Potential for Explosive Mixtures and Ignition in Wells.

REG In Saskatchewan all stimulus operations must comply to Saskatchewan Oil and Gas Conservation Regulations (1985) and the PDB ENV 13 – S-01 Saskatchewan Upstream Petroleum Industry Storage Standards. Discussion with Saskatchewan OHS may also be required.

c. Foaming

Operators may choose to foam for cleanout. The IRP 3 Committee acknowledges there are other cleanout methods as effective as foaming. The IRP 3 Committee does NOT endorse, or recommend, any single method of cleanout. Cleanout methods are selected at the Operator's discretion.

If an Operator does choose to foam, it is recommended to foam with a Regulator approved stable foam blend and follow Operator approved procedures. For information regarding foaming considerations see the supporting document Foam Cleanouts for guidelines pertaining to foaming.

d. Swabbing

Always swab as directed in Operator approved procedures.

REG In Alberta, space the swabbing return tank 15 m from the wellhead according to ID 91-3.

REG In Saskatchewan, space the swabbing return tank 45 m from the wellhead according to OHS requirements.

3.3.3.6 Primary Wellbore Integrity

Primary production can cause casing damage or failures to occur in the region of the producing zone. A casing inspection program should be developed as required.

The following topics are relevant to in situ heavy oil wellbore inspections.

a. Wellbore Condition

The wellbore or casing condition inspections may seek to identify issues with corrosion, ovality, wear, etc. Inspections may include, but not be limited to, the following:

- mechanical inspections (e.g. gauge ring / scraper runs)
- pressure tests
- casing inspection logs (e.g., multi-finger caliper, magnetic flux leakage, ultrasonic inspection, etc.)
- cement bond quality

b. Primary Wellbore Remediation

In instances where primary wellbore remediation is required, jurisdictional regulations apply.

REG In Alberta regulatory approval must be obtained for non-routine repairs according to [Bulletin 2009-07: Revisions to the Digital Data Submission System Regarding Interim Directive 2003-01](#).

REG In Saskatchewan, the appropriate regional office must be contacted to obtain approval for non-routine repairs.

c. Remedial Cementing

Efforts should be made at the planning stages to avoid the necessity of remedial cementing (see 3.1.2.1.1 Cement Integrity). Remedial cementing may be required:

- depending on gas migration and/or vent flow test results and jurisdiction,
- to repair casing damage,
- to ensure zonal isolation,
(as per [Directive 020: Well Abandonment](#) in Alberta and according to area specific guidelines in Saskatchewan)
- to establish cement top on initial completion, and
(per [Directive 009: Casing Cementing Minimum Requirements](#))
- to ensure ground water protection (per [Directive 020](#)).

Note. If discovered in initial completion that groundwater aquifers are not covered by cement, then remedial cement squeeze may be necessary.

REG In Alberta, any remediation must comply with [Directive 009: Casing Cementing Minimum Requirements](#).

REG In Saskatchewan, contact the appropriate regional office for program approval if remedial cementing is required.

3.3.4 SECONDARY WELL SERVICING

Secondary well servicing refers to well servicing that involves enhanced oil recovery (EOR), and is also known as secondary recovery. It includes both cold secondary recovery methods (e.g., solvent injection, water / polymer, etc.) and thermal recovery methods (e.g. SAGD, CSS, fireflood, etc.)

3.3.4.1 Offset Production

It is important to review offset production data and history to identify potential problems during well servicing operations. From the perspective of in situ heavy oil operations, wells can become sour after a short time on production. (see 3.1.2.3 Surface Casing Vent Flow and Gas Migration and 3.5.5 Surface Casing Vent and Gas Migration Monitoring).

To reduce potential problems consider the following data sources:

- area zonal communication;
- cumulative production of offset wells;
- BHP, H₂S content, NORM²; and
- use of EOR techniques, stimulation methods.

Additionally the *DRAFT Guidelines for Drilling Proximal to a SAGD Steam Chamber*³ is an excellent resource.

A thorough individual well history is important to assess the potential for well servicing problems. Well history data gathering should consider, but not be limited to, the items listed below.

- drilling history of the well, noting any problems encountered while drilling (particularly cementing problems)
- data on current cycle performance with regards to steam injection volumes versus cumulative or current production volumes (particularly producing temperature for anticipated BHT and BHP)
- data on previous workovers to identify any previously document casing problems
- produced fluid, gas analysis, and presence of NORM

Secondary well servicing should consider additional offset data including, but not limited to, the following items listed below.

- drilling history of offset wells, noting any problems encountered while drilling
- data on cumulative and/or current production levels
- data on producing temperature, BHP, H₂S content, gas to oil ratios, casing problems, and sand issues

² Naturally Occurring Radioactive Materials

³ This document is available on the IRP 3 landing page:
<http://enform.ca/publications/irps/heavyoilandoilsandsoperations.aspx>

- current status of wells (e.g., producing, steaming, or shut in) and possible effects that change of status could have on individual wells

Communication with other wells **can cause significant impact** ~~is especially important~~ for secondary recovery (see 3.1.1.2.2 Offset Wells and Proximal Operations and 3.5.3.10 Managing Proximal Operations). Secondary well servicing should consider, but not be limited to the following:

- data on well-to-well communication problems encountered while steaming or producing
- communication with other wells in area

Note. Communication between wells can change during the workover potentially impacting BHP and/or temperature.

3.3.4.2 Secondary Completions Planning

The following planning considerations are pertinent to secondary completions.

- Identify intervention and abandonment needs.
- Review NACE specifications for corrosion control.
(see 3.2.1.3.3 Thermal Production Casing Material Selection, b) Corrosion Considerations and c) Corrosion Mitigations)
- Define potential H₂S and CO₂ concentrations (see 3.1.2.3 Surface Casing Vent Flow and Gas Migration).
- Ensure equipment is properly rated for pressure, temperature, and possibility of future H₂S.
- Establish baseline gas migration data prior to completion
(see 3.5.5 Surface Casing Vent and Gas Migration Monitoring).
- Ensure communication and synergy with drilling for conditions and final design of the well (e.g., cement, deviations, doglegs, trouble spots, etc.).
(see 3.1.2 Operational Integrity)
- **Design well pads and patterns that efficiently accommodate service and completion work** (see 3.1.1.2 Multi-Operational Pad Planning).

REG Well completion design must accommodate a surface casing vent (SCV) assembly in accordance with jurisdictional regulations.

To prepare a well for secondary production, it is important to follow established procedures during wellhead installation. For detailed guidance on installation procedures refer to IRP 5.2.3 Wellhead Installation.

IRP Wellhead designs should accommodate existing and anticipated future operating parameters (e.g., workover, stimulation, EOR).

Refer to [IRP 5: Minimum Wellhead Requirements](#) and 3.4.3 Wellhead Design.

a. Welding

Welding procedures may include, but not be limited to, the following considerations.

- back welding
- stress-relieving
- non-destructive testing
- pressure testing
- availability of mill certifications
- corresponding heat numbers

IRP Operators shall have a welding procedure for severe service tubing head installations. See 3.2.3.8.6 Welding Requirements for details.

REG In Alberta a cement bond log is required in accordance with [Directive 051](#) to test the quality of a cement bond.

REG In Saskatchewan, a cement bond log may be required on a case-by-case basis. Contact the appropriate regional office.

b. Temperature

Temperature cycling in secondary recovery requires special consideration during secondary planning.

- High temperatures may de-rate materials.
(Refer to 3.2.1.3.1 Thermal Production Casing Loading)
Note. Cyclic loads and thermal stresses reduce the life of steel.
- Special maintenance of the wellhead may be required during heating and cooling cycles (e.g., re-torquing wellhead studs, maintenance or inspection of steam gate valves).

IRP All components shall be rated for the highest potential temperature of the well.

IRP Downhole equipment configuration shall allow for contraction and expansion.

c. Wellbore Access

It is important to design the wellhead with the ability to accommodate access to any production or working string being serviced for the purpose of well control.

Offset access for tubular and workover strings is important for workers to effectively and safely complete the well. Wellbore access should:

- accommodate wellhead height and any auxiliary equipment installed; and
- accommodate access necessary to install required BOPs and workover equipment.

d. Liners

It is recommended to design liner hangers to allow easy entry to RIH (run in hole) with tools and downhole equipment (see 3.2.1.3.6 Thermal Liner). If required, pressure test liner hanger during initial completion. During completion/workover ensure pressure and weight does not exceed hanger specifications.

e. Packers

During completion design, consider expansion and contraction caused by BHT change that may occur during operations and which may impact packers.

Additionally, consider placing debris seals over packers to keep slip and setting action free of materials that could cause packers to become stuck.

f. Seals and Connections

High temperatures can change the characteristics of seals and connections. To minimize the impact consider the following:

- selecting high temperature materials for seals, polymer, and steel;
- minimizing the number of instrumentation lines exiting the wellhead; (see 3.2.3.8.4 Instrument String Configurations)
- using premium thread for production string tubular connections; and (see 3.2.1.3.4 Thermal Production Casing Connection Selection)
- using slip seal assemblies/mandrel hang-off to terminate instrumentation coil tubing at surface.

g. Observation Wells

Install wellheads suitable to reservoir conditions on observation wellbores. In addition consider the following:

- Evaluate risk as downhole conditions change.
- Avoid threaded wellheads except for low pressure, non-perforated observation wells.
- Treat perforated observation wells the same as producing wells.

Note. Some observation well designs make it difficult or impossible to test casing bowl flange connections to wellhead or BOPs. This may require custom equipment design and manufacture.

3.3.4.3 Secondary Well Completions and Workovers

Due to the thermal nature of secondary recovery, it is important to be aware of the maximum well temperature where workover operations can be conducted safely.

REG All in situ heavy oil secondary well completions and workovers must comply with relevant jurisdictional regulations.

- [Directive 033: Well Servicing and Completions Operations - Interim Requirement Regarding the Potential for Explosive Mixtures and Ignition in Wells](#)
- [Directive 037: Service Rig Inspection Manual](#)
- [ID 91-3: Heavy Oil/Oil Sands Operations](#)
- [IRP Volume 7: Standards for Wellsite Supervision of Drilling, Completion and Workovers.](#)
- [Saskatchewan's Oil and Gas Conservation Regulations, 1985](#)
- [Saskatchewan Upstream Industry Storage Standards](#)

Additionally, completions and workovers should consider the following:

- spacing limitations due to existing production facilities (see [Appendix A: Well Servicing Equipment Minimum Spacing: Class IIA](#) and [Appendix B: Associated Well Servicing Equipment Minimum Spacing: Class IIA](#). For a combined diagram of spacing requirements for service rigs, drilling rigs and existing wells see: 3.1 Integrated Planning, Appendix A: Minimum Spacing Requirements for Multi-Operational Pads);
- accommodation for well type (e.g., horizontal, directional, slant, vertical, and well service classification);
- if applicable, ensure an ERP is in place and in accordance with jurisdictional regulations;
- if applicable, ensure procedures are in place to address venting of odorous compounds and to control noise during well servicing operations in accordance with jurisdictional regulations;
- evaluate the need for heavy kill procedures and develop procedures as required; and
- waste management in accordance with jurisdictional regulations (see 3.1.1.6 Waste Management).

3.3.4.4 Secondary BOP and Well Control Requirements

All secondary BOP configurations are considered Class IIA in accordance with [ID 91-3: Heavy Oil/Oil Sands Operations](#). Class IIA secondary wells have the following characteristics due to fluid(s) injection (other than water) into the formation at ambient temperatures:

- sandface reservoir pressure greater than a Class IIA primary well or with a bottomhole or injection pressure less than or equal to 21 MPa,
- H₂S release rate less than 0.001 m³/sec (see 3.1.2.3 Surface Casing Vent Flow and Gas Migration),
- includes all wells that are classified by the respective regulatory body as an “active” EOR scheme and
- any offset wells within 1000 m of a high pressure CSS well or within 300 m from any SAGD, fireflood, or solvent injection wellbore.

REG BOP components on a Class IIA secondary well must be tested to the pressures specified in [Section 8.147](#) of the [Oil and Gas Conservation Regulations](#). A 10-minute test must be conducted prior to servicing the first well of a program (i.e., change of Operator), and thereafter, within 7 calendar days. If the BOPs are moved to a new well within 7 calendar days of the original 10-minute test, BOP component pressure testing must be a minimum of 2 minutes.

Note. A 15 m kill line is required.

REG In Saskatchewan BOP components must comply with the [Saskatchewan Oil and Gas Conservation Regulations \(1985\)](#).

Refer to the following general secondary well control considerations:

- Determine if servicing BOPs requires full bore access to production casing. When moving tubing or removing tubing hanger, full access to wellbore is recommended.
- Review anticipated BHP and BHT.
- Review the type and volume of kill fluid required.
- Follow established kill procedures.
- Be aware of any special concerns resulting from pumping water into a thermal well during well kill. Consider temperature differences before pumping fluid down the well.
- Ensure kill procedures and fluids consider the effects of thermal downhole temperatures (see 3.2.2.7 Well Control Practices in Thermal Areas and 3.2.3.6 Drilling Proximal to a Steam Chamber).

- Non-routine well control procedures may be required, but not limited to, the following circumstances:
 - if a well will not hold a column of fluid (i.e., will not circulate under normal conditions)
 - if a well swabs while tripping tubing, etc.
 - if wells are over-pressured (refer to Operator's heavy kill procedures)
- Determine operations to be carried out (e.g., coil tubing [[IRP Volume 21: Coiled Tubing Operations](#)], wireline, continuous rod, flush by operations, etc.).
- Determine tools to be used that could affect BOP configuration/regulation.
- Strings too small for the existing pipe ram size may be pulled either with an annular BOP that includes rams to accommodate each tubing string, or a variable type ram.

a. Temperature

IRP All BOP components shall be temperature rated at, or above, the anticipated surface working temperature of the well being serviced.

Note. If a rod string needs to be pulled from a thermal well, do not exceed the maximum working temperature of the BOP elements.

For non-emergency conditions, 85°C is the maximum recommended wellhead temperature for servicing as recommended by the manufacturers. Temperatures above 85°C risk the integrity of well control elastomers unless appropriately risk assessed.

If there is potential for exposure to hot fluids during well servicing, then proper PPE needs to be available.

b. Auxiliary Tubing External Attachments

REG According to D037 "an annular preventer must be installed whenever electrical cables, small diameter tubing control, or circulating strings are being tripped." Other proposed modifications must be approved by the appropriate regional regulatory authority.

IRP A means to cut auxiliary items (e.g., capillary tubes, ESP cables, instrument cables) shall be available on the rig floor for tubing strings with auxiliary external attached lines, tubes, or cables, using Class II BOP (supplemented with an annular BOP) ~~may be used.~~

c. Offset Spool

The use of offset rams is generally discouraged for tripping offset tubing strings.

An offset spool is recommended below a thermally suitable, dimensionally standard BOP.

If multiple strings are to be handled, a back pressure valve should be available for reconfiguring the BOP stack.

REG While pulling tubing strings, each tubing string must be equipped with its appropriate ram and/or a variable ram to ensure well control (D037). Occasionally, with small tubing strings appropriately sized rams are not available. In these situations, modified designs must receive local regulatory approval.

d. Observation Well

Non-perforated observation wells do not require BOPs if the wellbore has been pressure tested.

If BOPs are used, they should be installed as required for the offsetting production wells.

e. Slant Wells

For wells slanted at surface, design consideration should ensure that loads induced due to the moment arm and weight of the BOP will not cause a structural failure of the near surface casing string(s) or leakage at the BOP or wellhead flanges. Support brackets or other means of supporting the BOP stack should be designed by a professional engineer.

3.3.4.5 Secondary Well Stimulation

Secondary well stimulation includes four key considerations: spacing, stimulus operations, foaming, and swabbing.

a. Spacing

The density of fluid being pumped may affect equipment spacing requirements. Refer to [Appendix A: Well Servicing Equipment Minimum Spacing: Class IIA](#) and [Appendix B: Associated Well Servicing Equipment Minimum Spacing: Class IIA](#) for spacing specifications.

For solvent injection operations, refer to [IRP Volume 8: Pumping of Flammable Fluids](#).

Note. Density under 920 kg/m^3 changes well treatment considerations and the well service classification.

Note. Stabilized foam cleanout operations do not change spacing from a Class IIA.

b. Temperatures

IRP Appropriate products shall be used for stimulations in situations with elevated wellbore temperatures (e.g., using N₂ rather than air for foam generation).

c. Stimulus Operations

REG All stimulus operations must follow established [OHS procedures](#).

REG Ensure stimulus operations (e.g., acidizing, fracturing, foam cleanout) are compliant with [Directive 033: Well Servicing and Completions Operations - Interim Requirement Regarding the Potential for Explosive Mixtures and Ignition in Wells](#).

REG In Saskatchewan all stimulus operations must comply with the [Saskatchewan Oil and Gas Conservation Regulations \(1985\)](#).

d. Foaming

Operators may choose to foam for cleanout. The IRP 3 Committee acknowledges there are other cleanout methods as effective as foaming. The IRP 3 Committee does NOT endorse, or recommend, any single method of cleanout. Cleanout methods are selected at the Operator's discretion.

If an Operator does choose to foam, it is recommended to foam with a Regulator approved stable foam blend and follow Operator approved procedures. For information regarding foaming considerations see supporting document Foam Cleanouts for guidelines pertaining to foaming.

3.3.4.6 Secondary Wellbore Integrity

Secondary production techniques can increase the risk of casing damage and failure due to thermally-induced stresses. A casing inspection program should be developed as required.

The following topics describe wellbore inspection considerations.

a. Wellbore Condition

The wellbore or casing condition inspections may seek to identify issues with corrosion, ovality, casing body and connections, wear, etc. Inspections may include, but not be limited to the following

- mechanical inspections (e.g. gauge ring / scraper runs)
- pressure tests

- casing inspection logs (e.g., multi-finger calliper, magnetic flux leakage, ultrasonic inspection, etc.)
- cement bond quality (as per [*Directive 051: Injection and Disposal Wells – Well Classifications, Completions, Logging, and Testing Requirements*](#))
- follow-up cement bond quality as required
- temperature logs

Results of the casing inspection can identify wellbore conditions which may result in one, or all, of the following constraints:

- designate as POW (producer-only well),
- operating pressure and temperature restrictions,
- repair wellbore damage, and
- wellbore shut-in and/or abandonment.

b. Deformation Classifications

Consider developing generic deformation classifications based on reduced ID. Table 1 below is a guideline to develop deformation classifications.

Table 1. Deformation Classifications

Deformation Severity Class	Amount of Deformation in Connection (mm)	Amount of Deformation in Pipe Body (mm)	Standard
1	⇒<3	<5	Ok to steam.
2	3-4	5-7	Ok to steam.
3	5-6	8-9	Requires pressure test before steaming.
4	7-8	10-12	May or may not Cannot be steamed dependent on location of deformation and regulatory review—Well may be is classified as POW and can be purged and monitored or plugged while steaming around it.
5	>8	>12	May or may not Cannot be steamed dependent on location of deformation and regulatory review—Well may be shall be plugged or repaired before steaming operations in the area. Should Cannot be POW until patched or repaired.

c. Wall Loss Class

Consider developing generic classes based on wall loss as illustrated in Table 2.

Table 2. Wall Loss Classes

Wall Loss Class	% Wall Loss	Standard
A	0-40	OK to steam.
B	41-50	Requires a pressure test before steaming.
C	51-70	Cannot be steamed. Well is classified as POW and can be purged and monitored or plugged while steaming around it.
D	71+	Cannot be steamed. Well shall be plugged or repaired before steaming operations in the area. Cannot be POW until patched or repaired.

d. Secondary Wellbore Casing Remediation

In instances where secondary wellbore remediation is required, jurisdictional regulations apply.

REG In Alberta regulatory approval must be obtained for non-routine repairs according to [Bulletin 2009-07: Revisions to the Digital Data Submission System Regarding Interim Directive 2003-01.](#)

REG In Saskatchewan, the appropriate regional office must be contacted to obtain approval for non-routine repairs.

REG Discussions must be initiated with the Regulator if wellbore integrity is jeopardized before proceeding with the repair.

~~e. Casing Breaks/Parted Casing/Collapsed Casing~~

If a **complete casing break of the casing** is suspected, avoid pulling tubing out; a shift may result and dramatically escalate the complexity of abandonment.

After well servicing, sufficient tubing should be left in the well to facilitate future access to the **depth of the payzone entire wellbore**.

If a serious casing anomaly is encountered, consider installing a casing patch or liner tie-back, removable shear liners, or a permanent slim hole.

Consider downhole abandonment (per [Directive 020](#)) prior to conducting uphole casing repairs as access to the lower wellbore can sometimes be lost.

f. Sulphide Stress Corrosion Cracking

The potential for sulphide stress corrosion cracking and subsequent casing failure due to the increase of H₂S during production may occur. Refer to 3.2.1.3.3 Thermal Production Casing Material Selection, b) Corrosion Considerations and c) Corrosion Mitigations along with 3.5.3.3 Corrosion Mitigations and 3.5.3.4 Sand Management and Erosion for more information.

g. Remedial Cementing

Remedial cementing in secondary applications is similar to primary applications in the following circumstances:

- gas migration and/or vent flow test results and jurisdiction,
- to ensure zonal isolation (per [Directive 020](#)),
- to establish cement top on initial completion (per [Directive 009](#)), and
- to ensure ground water protection (per [Directive 020](#)).

Note. If discovered in initial completion that groundwater aquifers are not covered by cement, then remedial cement squeeze may be required.

REG In Alberta, any remediation must comply with [Directive 009: Casing Cementing Minimum Requirements](#).

REG In Saskatchewan, contact the appropriate regional office for program approval if remedial cementing is required.

Consider the following special circumstances for secondary applications:

- Avoid water pockets to prevent flashing and pipe collapse.
(see 3.2.1.3.1 Thermal Production Casing Loads (c) Collapse)
- Use LCM if necessary.
- Determine and control free water content.

3.3.5 WELL SERVICING EQUIPMENT SPACING

Well servicing equipment spacing requirements are summarized in Appendix A and Appendix B. A detailed spacing matrix is available in Appendix C. It is recommended to reproduce Appendices A, B, and C and post them in a visible area inside the doghouse.

[Appendix A](#): Well Servicing Equipment Minimum Spacing: Class IIA Service Rig

[Appendix B](#): Associated Well Servicing Equipment Minimum Spacing: Class IIA

[Appendix C](#): Well Servicing Spacing Matrix

A larger version designed for 11x17 printing are available on the IRP 3 landing page at:

<http://enform.ca/publications/irps/heavyoilandoilsandsoperations.aspx>

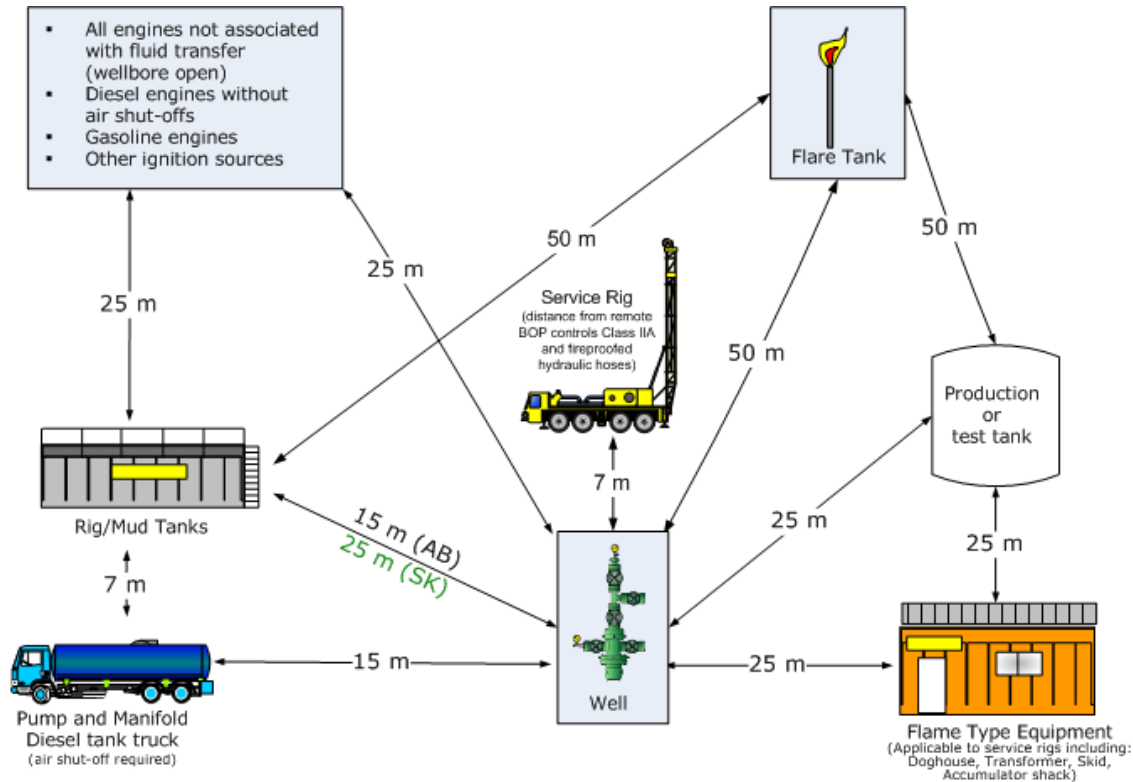
Note. Locate production POP tanks no closer than 7 m from well. Tanks must be empty at all times and disconnected or locked out during well servicing operations.

3.3.6 WELL ABANDONMENT

REG Routine abandonment must be conducted as per [Directive 020](#) in Alberta. Non-routine abandonments, as defined by [Directive 020](#), require approval before work is started.

REG All abandonments in Saskatchewan require approval.

APPENDIX A: WELL SERVICING EQUIPMENT MINIMUM SPACING: CLASS IIA



Class IIA Primary:

a well with a sandface reservoir pressure equal to or less than the hydrostatic pressure that would be exerted at the sandface if the well were filled with formation fluids.

- **Kill line not required.**
- **10-minute BOP pressure test on first hole, change of operator or jurisdiction and every 30 days.**

Class IIA Secondary:

a well with a sandface reservoir pressure greater than the hydrostatic pressure that would be exerted at the sandface if the well were filled with formation fluids. It occurs by virtue of injection into the formation of fluid(s) other than water at ambient temperatures. This includes all wells that are part of an active EOR project and approved by the ERCB and any offset wells within 1000 m of an EOR well.

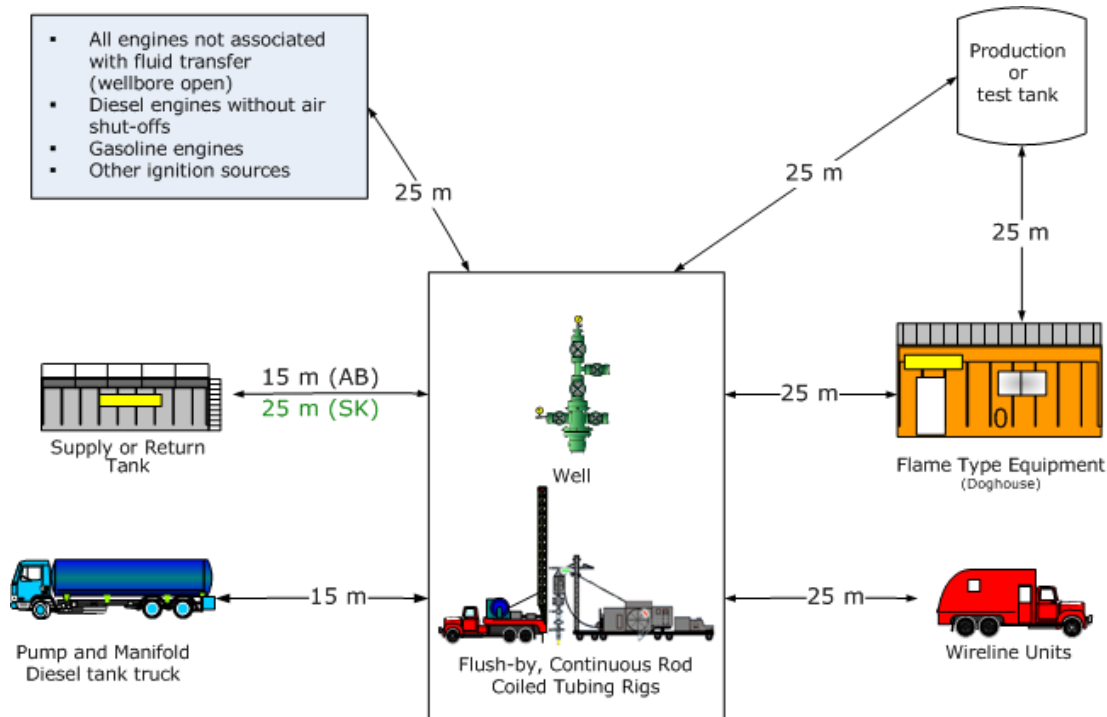
- **15 m kill line required.**
- **10-minute BOP pressure test prior to servicing first well, change of operator or jurisdiction and every 7 days.**
- **If the BOPs are moved to a new well within 7 calendar days of the original 10-minute test, BOP component pressure testing must be a minimum of 2 minutes.**

Notes:

- All distances noted are minimum distances between equipment.
- All measurements are from the nearest point of any equipment.
- Fluids pumped that are lighter than 920 kg/m³ must be pumped at a distance of 50 m from the wellhead.
- Spacing exemptions may be granted by the Regulator.
- Representation is NOT to scale.
- Adapted from [Directive 037 Service Rig Inspection Manual](#) and [ID 91-03: Heavy Oil/Oil Sands Operations](#).

APPENDIX B: ASSOCIATED WELL SERVICING EQUIPMENT

MINIMUM SPACING: CLASS IIA



Class IIA Primary:

a well with a sandface reservoir pressure equal to or less than the hydrostatic pressure that would be exerted at the sandface if the well were filled with formation fluids.

- **BOP pressure test as per IRP 21.**

Class IIA Secondary:

a well with a sandface reservoir pressure greater than the hydrostatic pressure that would be exerted at the sandface if the well were filled with formation fluids. It occurs by virtue of injection into the formation of fluid(s) other than water at ambient temperatures. This includes all wells that are part of an active EOR project and approved by the ERCB and any offset wells within 1000 m of an EOR well.

- **BOP pressure test as per IRP 21.**

Notes:

- All distances noted are minimum distances between equipment.
- All measurements are from the nearest point of any equipment.
- Fluids pumped that are lighter than 920 kg/m^3 must be pumped at a distance of 50 m from the wellhead.
- Exemptions may be granted by the Regulator.
- Representation is NOT to scale.
- Adapted from [Directive 037: Service Rig Inspection Manual](#) and [ID 91-03: Heavy Oil/Oil Sands Operations](#).

APPENDIX C: WELL SERVICING SPACING MATRIX

Equipment	Distance shown in metres (m)					
	Wellhead	Production Tanks (contains HC)	Rig Tank	Tank Truck (c/w PASO)	Power Line / Pole	Service Rig / Continuous Rod Rig
Service Rig / Continuous Rod Rig		25			H	A
Pipe Handler	6 ^B		15			
Wellhead		25	15 ^E	15		
Power Tongs / Swivel (c/w PASO)	7					
Power Line / Pole		7				H
Pressure Truck (c/w PASO)	15 ^D		15			
Production Tanks (contains HC)	25		15 ^E	7	7	25
Tank Truck (c/w PASO)	15	7	7			
Rig Pump	15		7			
Rig Tank	15 ^E	15 ^E		7		
Wireline Unit (c/w PASO)	25 ^G	15				
Wireline Unit c/w mast, PASO		15				A
Steamer/Hot Oiler	25	25				
Nitrogen Unit (flameless)	15	15	15			
Nitrogen Unit (flame vaporizer)	25	25	25			
Diesel Engines with PASO	7	7	7			
Diesel Engines without PASO	25	25	25			
Trailers / Doghouse	25	25	25			
Boiler	25 ^E	25	25			
High Pressure Pumper (e.g.cementer)	15	15				
Gasoline Engines	25	25	25			
Portable light plants/generators	25 ^E	25				
Flushby Unit (c/w PASO)		15				A
Bailing Tanks	<1 ^C					
Coil Tubing Unit		15				
Continuous Rod Welder	25	25				
Vacuum Truck (c/w PASO)	7 ^F					

Notes:

PASO = positive air shut off
 measurement is from well center line to air intake
 Other Ignition Sources (MCC's, process buildings, etc.)

A = closest guyline + mast height + 3 m

B = exhaust to closest well (not the well being worked on)

C = may be adjacent to the well but must be removed as soon as bailing operations are completed.

D = Primary may be 7 m with ERCB exemption

E = in Sask 25 m

F = closest point from anywhere on truck to any part of well (s)

G = May be 15 m with ERCB exemption

H = Mast height + 3 m. Anchor lines do not pass over or under a live power line

[Adapted from ID 91-03: Heavy Oil/Oil Sands Operations.](#)