



Water Service Wells –
Summary Information
VERSION 3.3: March 2021

About the Commission

The BC Oil and Gas Commission (Commission) is the single-window regulatory agency with responsibilities for regulating oil and gas activities in British Columbia, including exploration, development, pipeline transportation and reclamation.



The Commission's core roles include reviewing and assessing applications for industry activity, consulting with First Nations, ensuring industry complies with provincial legislation and cooperating with partner agencies. The public interest is protected by ensuring public safety, protecting the environment, conserving petroleum resources and ensuring equitable participation in production.

VISION

Safe and responsible energy resource development for British Columbia.

MISSION

We provide British Columbia with regulatory excellence in responsible energy resource development by protecting public safety, safeguarding the environment and respecting those individuals and communities who are affected.

VALUES

Transparency

Is our commitment to be open and provide clear information on decisions, operations and actions.

Innovation

Is our commitment to learn, adapt, act and grow.

Integrity

Is our commitment to the principles of fairness, trust and accountability

Respect

Is our commitment to listen, accept and value diverse perspectives.

Responsiveness

Is our commitment to listening and timely and meaningful action.



Additional Guidance

As with all Commission documents, this manual does not take the place of applicable legislation. Readers are encouraged to become familiar with the acts and regulations and seek direction from Commission staff for clarification. Some activities may require additional requirements and approvals from other regulators or create obligations under other statutes. It is the applicant and permit holder's responsibility to know and uphold all legal obligations and responsibilities.

Throughout the manual there are references to guides, forms, tables and definitions to assist in creating and submitting all required information. Additional resources include:

- [Glossary and acronym listing](#) on the Commission website.
- [Documentation and guidelines](#) on the Commission website.
- [Frequently asked questions](#) on the Commission website.
- [Advisories, bulletins, reports and directives](#) on the Commission website.
- [Regulations and Acts](#) listed on the Commission website

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Manual Revisions

The Commission is committed to the continuous improvement of its documentation. Revisions to the documentation are highlighted in this section and are posted to the [Documentation Section](#) of the Commission's website. Stakeholders are invited to provide input or feedback on Commission documentation to OGC.Systems@bcogc.ca or submit feedback using the [feedback form](#).

Version Number	Posted Date	Effective Date	Chapter Section	Summary of Revision(s)
3.1	October 8, 2019	November 1, 2019	Appendix F	Minor edits to the section were made to provide further clarification on bottom hole injection pressure and temperature logs.
3.2	November 5, 2020	December 1, 2020	Appendix	The Packer Isolation Testing Appendix was removed. Users should now refer to section 9.1.3 of the Oil and Gas Activity Operations Manual for further information on Packer Isolation Test Procedures. Minor clarification to Hydraulic Isolation Temperature Log in Appendix E.
3.3	March, 26, 2021	March 26, 2021	3.3	Added instructions for consent required for disposal into a pool.

Preface

This document provides guidance regarding reservoir management and the regulation of disposal wells, injection wells, and water source wells. Disposal may be into depleted hydrocarbon pools or regional saline water saturated formations. Water injection is specifically for the recovery enhancement of oil production pools. Deep source wells target regional saline water saturated formations that have the potential to be used conjunctively for water disposal.

Historically, water source wells were drilled to supply injection wells for water flooding of oil pools. Disposal wells primarily handled by-product effluent from high water-ratio producing gas and oil wells. The current focus on exploitation of unconventional resources – shale gas and tight gas – has increased the need for water for hydraulic fracture stimulation, with a related requirement for deep disposal of increased stimulation flowback volumes.

In this document, the term “usable water” refers to water with total dissolved solids (TDS) of 4,000 PPM or less.

Chapter 1: Deep Water Source Wells

A "water source well" is specifically defined in the Petroleum and Natural Gas Act as "a hole in the ground drilled to obtain water for the purpose of injecting water into an underground formation in connection with the production of petroleum or natural gas" (i.e., groundwater used for enhanced recovery from oil pools or hydraulic fracture stimulation of wells). A water source well may target aquifers or storage reservoirs ranging from shallow unconfined quaternary sediments to deep confined saline aquifers.

This document provides guidance related to water source wells targeting aquifers where there is storage reservoir potential for both disposal/injection and/or water sourcing. Guidance for water source wells in shallower or unconfined aquifers that do not have water disposal potential is provided in the [Supplementary Information for Water Source Wells](#) document.

1.1 Permit

A water source well requires the submission of a normal Well Permit application form and approval prior to drilling; the well operational type "water source". Information on the Well Permit application process can be found in the [Oil and Gas Activity Application Manual](#) on the Commission's website. Guidance regarding requirements for water source well testing, monitoring, and reporting can be reference in the [Supplementary Information for Water Source Wells document](#).

Please Note:

A water well drilled for the purpose of supplying water for drilling, camps, hydrostatic testing of pipelines, etc., does not classify as a "water source well", but would be a "well" under the Water Act. In this case, a Well Permit is not required, and the well would be regulated under the Water Act and the Groundwater Protection Regulation. Information in this document does not apply to non-water source wells.

1.2 Well Classification, Spacing and Tenure

A water source well is assigned a classification (development, exploratory outpost or exploratory wildcat) based on the provisions of Section 2 of the Drilling and Production Regulation, with well data receiving a confidential period as specified in Section 17 of the Oil and Gas Activities Act (OGAA) General Regulation. For well classification determination, the spacing distance used is that which applies in the nearest offsetting designated pool (for example, a gas spacing area distance if measured from a gas pool).

Well spacing and target area restrictions do not apply to a water source well. Production of water does not require ownership of the subsurface tenure in the completed zone; however, some water source wells have produced sufficient rates of associated natural gas, typically evolving from solution in water with pressure loss, to require capture and conservation. In such a case the primary product of the well is changed to “gas” (despite the well purpose being for water), requiring valid petroleum and natural gas tenure for the formation over the complete gas spacing area. Holding tenure to a water producing formation is advised.

Currently, no additional application or approval is required for withdrawal of water from a subsurface aquifer, unless the groundwater extraction project is designed to operate at a rate of 75 liters/second or greater, in which case the BC Environmental Assessment Office permitting process applies.

1.3 Wellbore Integrity

For existing wells, all porous zones, in addition to the source zone, must be isolated by cement.

All new wells drilled for the purpose of water source must ensure that:

- Surface casing is set below the deepest usable water zone and cemented to surface, or
- If surface casing is not set below the deepest usable water zone, the next casing string is cemented to surface, and
- Hydraulic isolation is established between all porous zones.

1.4 Notification and Reporting

For each month during which water is produced the production data must be reported to Petrinex. The water source well event must be linked to a facility.

Other reporting requirements for water source wells are outlined in the [Supplementary Information for Water Source Wells](#) document.

1.5 Reservoir Pressure Testing

In accordance with Section 73(2) of the Drilling and Production Regulation, the static bottom hole pressure of each water source well accessing deep groundwater must be measured each calendar year. All reservoir pressure tests conducted must be submitted to the Commission within 60 days of the end of the test.

Chapter 2: Water Injection Wells

Water injection into a suitable oil pool, termed a “waterflood,” can achieve a higher oil recovery than by primary depletion alone. Prior to water injection, a Pressure Maintenance Waterflood Approval is required from the Commission, issued as a Special Project Order under Section 75 of the Oil and Gas Activities Act. The waterflood approval specifies wells that may be used for injection service, as well as other operating conditions. Details of the waterflood application and approval process are provided in the guideline [Pressure Maintenance or Improved Recovery](#).

2.1 Permit

For a water injection well, the standard Well Permit application form and requirements apply; the well operational type is “water injection.” Information on the Well Permit application process can be found in the [Oil and Gas Activity Application Manual](#) on the Commission’s website.

2.2 Well Classification, Spacing and Tenue

A water injection well is classified (development, exploratory outpost or exploratory wildcat) and receives a confidential period based on the standard rules of Part 2 of the Drilling and Production Regulation, with well data receiving a confidential period as specified in Section 17 of the Oil and Gas Activities Act General Regulation. For well classification determination, the spacing distance used is that which applies in the nearest offsetting designated pool (for example, a gas spacing area distance if measured from a gas pool).

The well permit holder is required to have registered ownership, or consent from the owner, of subsurface petroleum and natural gas tenure for the formation in which injection is occurring. In the Dominion Land Survey this is an area of ¼ section; in the National Topographic System of survey this area is one unit of land. Most waterflood operations in pools with mixed interests are unitized. A Unit Agreement or Unit Operating Agreement is separate from a Commission Special Project Order to waterflood.

Well spacing and target area restrictions do not apply to a water injection well. However, owners of offsetting wells, outside of the waterflood approval area, may raise technical concerns with the Commission regarding potential negative impact of injection on their producing well(s). Past experience has shown that such wells generally benefit from increased oil recovery.

2.3 Wellbore Integrity and Logging

All new wells drilled for the purpose of injection must ensure that:

- Surface casing is set below the deepest usable water zone and cemented to surface or, if surface casing is not set below the deepest usable water zone, the next casing string is cemented to surface.
- Hydraulic isolation is established between all porous zones. A temperature log is frequently used to confirm hydraulic isolation but other methods may be proposed by the permit holder. Guidance for conducting a temperature log can be found in Appendix E.

The permit holder must conduct adequate logging to demonstrate hydraulic isolation of the injection zone and porous zones. For existing wells, all porous zones, in addition to the injection zone, must be isolated by cement. If the production casing is not cemented to surface or cement returns to surface were not maintained during setting, a log must be run to locate the cement top in addition to the required hydraulic isolation log. The preferred cement evaluation/inspection log is a radial log displaying 3' amplitude, 5' VDL and cement map with both a non-pressure pass and pressure pass. Log results and interpretation must be submitted as part of the pressure maintenance application. Permit holders may reference AER Directive 51 for logging guidelines.

Wellbores with cement squeeze abandonments occurring above the injection zone may not be suitable for injection service. Cement squeeze abandonments have been prone to isolation failure and it is problematic to demonstrate continued seal when multiple packers are used to isolate former completion intervals. Application for injection service for a well with uphole completion intervals must adequately address these concerns.

Applications for wells greater than 10 years in age must include new full length casing inspection and cement evaluation logs. A recent log may be suitable if the well has not undergone significant changes since the log was conducted. The casing inspection log should evaluate both internal and external metal loss; a log that consist of only caliper finger results will be considered incomplete. Full length casing inspection and cement evaluation logs to packer depth will be considered if the packer is difficult to remove and a temperature log can confirm hydraulic isolation. The Commission recognizes that in wells which have been operating for a long time, the removal of the packer can be costly, time-consuming, and, in some cases, damaging to casing integrity. In these circumstances the Commission will generally accept casing inspection logs which are run to packer depth; these logs avoid risk but still provide valuable information. Logs run to packer depth may require release of the packer from tubing using an on-off tool and pulling tubing. The Commission will accept through-tubing casing inspection logging in order to avoid pulling tubing altogether.

Section 16(2)(a) of the Drilling and Production Regulation (DPR) requires that production packers be set as near as practical above the injection interval. The Commission expects packers to be set within 15m of the top of the completed interval in most circumstances, therefore; a casing inspection log run to the depth of the packer should provide reasonable assurance that there is good casing condition down to the proposed

injection zone. Where there are porous zones below proposed injection interval, the Commission expects the permit holder to isolate the zones by a packer or a bridge plug. In these situations a packer should be set as close as practicable below the injection interval. Packer removal may be required where there are downhole porous zones not isolated by packer or bridge plug or if the production packer is not set close enough to the injection zone resulting in porous intervals not being logged.

The pressure maintenance application also requires the casing age, grade and collapse pressure of wells within the area of pressure influence (within 3km recommended) to be tabulated. These values may be a further limiting factor to the maximum wellhead injection pressure as casing collapse in the vicinity of an injection well is of concern. An appropriate safety factor must be applied if casing integrity has degraded with age.

2.4 Maximum Wellhead Injection Pressure

Injection pressure must not exceed the formation fracture pressure and the recommended practice is to not exceed 90 per cent of this value. The Commission has been gradually amending waterflood approvals and updating conditions to include a specific maximum wellhead injection pressure value for water injection wells. Any changes to injection fluid density, usually due to salinity, must be accounted for. Injection pressures above formation fracture gradient may lead to over-pressuring of formations above and below the completed formation, resulting in well drilling and operating safety hazards, and a potential loss of producible hydrocarbons.

2.5 Formation Pressure Monitoring

Production performance of oil wells in the waterflood project, typically increasing oil rate and reduction in producing gas-oil ratio, indicate the effectiveness of waterflooding via connective displacement of fluids and re-saturation of the free gas. Ongoing and cumulative voidage balance (production withdrawal vs injection volumes, at comparative reservoir conditions of temperature, pressure and relative solubility) should prevent the reservoir pressure from exceeding initial conditions. Periodic bottom-hole pressure testing of injection wells is further confirmation that water injection is not resulting in areas of localized high pressure due to poor connectivity to producing wells.

Once production has permanently ceased from a waterflood the injection into the pool must cease. A water injection well in a depleted pool may be a good candidate for water disposal operations. Should an operator wish to re-purpose a water injection well for disposal service, an application and subsequent approval for water disposal is required.

In cases where a pool has reached a state of average pressure which significantly exceeds the initial reservoir pressure the operator may be required to submit a plan to reduce the pool pressure, which may include fluid flow-back from wells.

2.6 Packer Isolation Testing

Annual packer isolation tests must be conducted in accordance Section 16(3) of the Drilling and Production Regulation. The test must follow the procedure outlined in Section 9.1.3 of the [Oil and Gas Activity Operations Manual](#). Continuous monitoring of casing and tubing pressure is considered the primary wellbore integrity detection method. The annual packer isolation is considered a secondary level of integrity detection and is only conducted up to 1,400 kPa.

Please Note:

Before water injection operations begin, a pressure integrity test must be conducted. This is the standard pressure testing requirement when any completion or workover is conducted and is not the same as a packer isolation test. In a pressure integrity test the casing or casing/tubing annulus is pressure tested to a minimum pressure of 7,000 kPa for 10 minutes prior to the commencement of injection or disposal operations (see Chapter 9 of the [Oil and Gas Activity Operations Manual](#) requirement for activating suspended wells and suspending wells). A pressure test is considered successful if the pressure does not vary by more than three per cent during the test period.

2.7 Facilities

A separate facility application must be submitted to the Commission for additional surface equipment required for the injection well.

2.8 Notification and Reporting

The quantity and rate of fluid injected into a well must be metered, as per Section 74 of the Drilling and Production Regulation.

For each month during which water is injected into the well, injection data, including total injection hours, volume and wellhead tubing pressure, must be reported in Petrinex. Injection data must be reported by the 20th day of the month following injection.

A change in operations, such as at start-up or a rate change, can result in momentary pressure spikes. The wellhead pressure reported in Petrinex is the maximum pressure, sustained for a period of a minimum of five minutes continuous duration, experienced during the reported month.

When an injection well is not anticipated to be utilized for a period of one year or more, the status of the well event should be updated to “Suspended.”

Chapter 3: Water Disposal Wells

Water produced in association with oil and gas, either formation water or well completion flow-back fluid, must be disposed into a subsurface formation via an approved disposal service well. Disposal is not permitted into an aquifer containing water usable for domestic or agricultural purposes, or a zone that may pose risk of contamination of such a water aquifer. The protection of water resources is of primary importance to the Commission. Disposal formations are generally deeper than 800 metres below ground level.

3.1 Deep Disposal Options

Disposal formations must be contained by impermeable cap and base formations, competent to contain fluid within the area of influence. With the recent development of unconventional resources, such as shale, the bounding formations must also be considered for future hydrocarbon potential and must not be sterilized from development by disposal into proximal formations that would preclude future fracture stimulation for hydrocarbon production.

3.1.1 Depleted Hydrocarbon Pools

Depleted hydrocarbon pools have demonstrated the ability to contain a fluid at initial discovery conditions. Depleted pools contain a known reservoir void space, based on the cumulative production volume of fluids, converted to their volume under reservoir conditions and accounting for relative solubility. This voidage volume can be used to approximate ultimate fill-up capacity. Periodic reservoir pressure measurements will confirm this prediction. In some cases, where it can be demonstrated that disposal will not be detrimental to ultimate pool hydrocarbon recovery, approval has been granted to dispose water into a producing pool below the gas/water or oil/water contact.

3.1.2 Deep Aquifers

Deep aquifers at a variety of depths contain water of high salinity trapped underground for millions of years. These aquifers vary widely in thickness, reservoir quality and area. Capacity for disposal of water, a virtually incompressible fluid, introduced into a system of limited compressibility, is determined by aquifer size, if not connected to a pool of compressible fluid (gas) providing additional storage capacity.

Aquifers targeted for disposal are generally regional in area. Some have shown a vast capacity for disposal, with limited, if any, pressure required at surface for injection, accepting liquids “on vacuum”. During injection

some aquifers show characteristics of compartmentalization by geologic barriers of low porosity and permeability or structure. As well, over the disposal life of a well the pressure required to sustain disposal rates typically increases in part due to mobilization of fines and precipitates that gradually block pore throats, that may not be remediated by work-over operations.

3.2 Permit

For a new purpose-drilled disposal service well, the standard Well Permit application form and requirements apply; the well operational type noted as “water disposal”. Information on the Well Permit application process can be found in [Oil and Gas Activity Application Manual](#) on the Commission’s website.

To convert a new or existing well to disposal service, an amendment to the existing Well Permit is not required. The following steps are required:

- Submit a Notice of Operation to the Commission prior to work on well (<http://www.bcogc.ca/node/5753/download>)
- Submit an application for deep well disposal service, an approval contains specific operation, testing, monitoring and reporting requirements (<http://www.bcogc.ca/node/8206/download>)
- Facility permit application, for a disposal facility (<http://www.bcogc.ca/node/13267/download>)
- Update the status of the well in Petrinex once injection begins (required to report injection volume and pressure).

3.3 Well Classification, Spacing and Tenure

A water disposal well is classified (development, exploratory outpost or exploratory wildcat) and receives a confidential period based on the standard rules of Part 2 of the Drilling and Production Regulation, with well data receiving a confidential period as specified in Section 17 the Oil and Gas Activities Act General Regulation. For well classification determination, the spacing distance used is that which applies in the nearest offsetting designated pool (for example, a gas spacing area distance if measured from a gas pool).

Well spacing and target area restrictions do not apply to a water disposal wells. However, it is advised that a disposal well be completed no closer than 100 metres to a lease boundary to other ownership. In general, this will reduce the opportunity for objection due to competitive disposal use of a reservoir.

. A disposal well permit holder is required have registered ownership, or consent from the owner (via a [Letter of Consent to Inclusion in a Reservoir Project](#)), of subsurface petroleum and natural gas tenure of the

disposal formation, leasing the reservoir void space for fluid storage. In the Dominion Land Survey this is an area of ¼ section, in the National Topographic System of survey this area is one unit of land.

If the proposed disposal interval is in a pool, as mapped by the Commission, where existing wells are completed for oil or gas, the disposal well permit holder is required to have registered ownership, or consent from the owner, of all wells that are completed into the pool and where the completion interval has not been zonally abandoned. Where a pool is of large areal size with potentially hundreds of wells involved, only wells that will be contacted by fluids or pressure from the project operation are considered. This consent can be obtained by way of [letters of non-objection](#). If the disposal well permit holder is not able to obtain a reply from the other owners in the pool, they may include a copy of their dated letter sent to the company, as proof of trying to obtain non-objection. The public notice period will be the owner's last opportunity to object if they did not reply

3.4 Disposal Well Approval Application

The Commission application guideline [Deep Well Disposal of Produced Water/Nonhazardous Waste](#) provides a comprehensive listing of the information for inclusion in an application. Applications should be submitted in PDF format to Reservoir@bcogc.ca. Applications to the Commission are public documents. If there are confidential sections in the application based on specific proprietary data, such a seismic interpretation, either clearly mark those pages with 'CONFIDENTIAL' or submit a second "public," redacted PDF.

For the purposes of defining disposal fluids, produced water includes recovered fluids from a well completion or workover operation (including flowback fluids from fracture stimulations); the same application/approval applies for disposal of associated produced water, flowback fluids, or both. Further reference to "disposal" or "produced water" in this document includes both sources.

Disposal of oilfield **nonhazardous waste** (NHW) down a wellbore follows these same criteria, with the additional requirement of obtaining a waste discharge permit under the authority of the Environmental Management Act (called an EMA Permit). The Commission application guide [Deep Well Disposal of Produced Water/Nonhazardous Waste](#) provides a comprehensive listing of information required. Once a Section 75 Order has been issued by the Commission for NHW disposal, the well is automatically approved for produced water disposal. If at any time there is not a valid EMA permit issued for the well, produced water may continue to be disposed.

Upon receipt of an application, a notice of application for operation of a disposal well is posted to the Commission's website for a 21-day period to allow any concerns to be filed with both the Commission and the applicant. The notice includes contact information for obtaining a copy of the application. During the posting period applicants are required to provide a copy of the application to requesting parties. Requesting

parties are not required to demonstrate ownership of off-set wells or tenure rights. Additional information on the posting of application notice and the process regarding the filing of objections is available [here](#).

An approval to operate a water disposal well is granted by the Commission as a Special Project Order under Section 75 of the Oil and Gas Activities Act. The approval contains conditions that must be met to remain valid, including those in the following section.

3.5 Disposal Well Approval Conditions

3.5.1 Maximum Wellhead Injection Pressure

Disposal injection pressure must not exceed the formation fracture pressure. The Commission approved maximum wellhead injection pressure, when calculated to bottom-hole pressure, will not exceed a value of 90 per cent of the formation fracture pressure. The Commission has conducted extensive data analysis to populate a provincial database of fracture gradients for several common disposal formations in NEBC. These values are derived from hydraulic fracture treatment ISIP values, accepted as indicators of the formation fracture pressure. Caveats for usage of this data are that reported ISIP values lack precision, often rounded to the nearest MPa, and values occasionally vary substantially between locations in close proximity. Mapping and contouring of values has provided a methodical approach to establish a reliable value for the area of influence for a disposal well, a value that is not overly influenced by a single anomalous reported number. These contoured maps are available on our website on the [Subsurface Disposal page](#).

Variability in disposal fluid density, due to salinity or composition, requires use of a hydraulic wellbore gradient to calculate a conservative wellhead pressure value. The Commission typically utilizes a value of 11.0 kPa/m as the disposal fluid gradient for calculating the maximum wellhead injection pressure. However, disposal fluid samples have been noted to have values as high as 11.7 kPa/m. Very high salinity may be more common with recycling of hydraulic fracture fluid prior to disposal. The well operator is responsible for adjusting the wellhead injection pressure to a lower value if a higher density/gradient value fluid is being disposed. The Commission will reduce the approved maximum wellhead pressure when there is evidence of higher density/gradient values, from disposal fluid samples or static gradient tests. The Commission advises well operators to create and use a chart of fluid density for the individual well injection depth, to adjust injection pressures below the maximum approved value in order to remain below the formation hydraulic fracture pressure.

Measured or inferred competency of bounding formations and wellbore cement are not criteria to inject above formation fracture pressure, as existing natural fractures, faults, planes of weakness and wellbores within the area of influence may provide migratory paths for fluids at a pressure below the formation fracture pressure. Injection above formation fracture gradient may lead to over-pressuring of formations in proximity above and below the completed formation resulting in a well drilling and operating safety hazard and potential loss of producible hydrocarbons.

Recent studies indicate that the formation closure pressure, measured at the injection interval, may be a more suitable limit for injection pressure for two reasons: (1) it provides a conservative safety factor as existing fractures cannot propagate and provide a conduit for waste fluids potentially out of the disposal zone, and (2) it is determined from standardized calculation methods. Further study of the relationship

between closure pressure and an ISIP in various formations is on-going. Subsequent releases of this document will detail results as they become available.

See **Section 3.9 Step-Rate or Mini-Frac Formation Testing** for information on direct testing for formation fracture pressure.

3.5.2 Maximum Formation Pressure

Disposal well approvals contain a condition limiting the ultimate formation “fill-up” pressure to a specific value. The maximum formation pressure limit provides confidence of containment of the fluids injected, at a pressure value that is within reasonable proximity to that which provided an existing geologic seal. Existing natural fractures, faults, planes of weakness and wellbores within the area of influence may provide migratory paths for fluids at a pressure that remains below the formation fracture pressure. The limit is also a measure to protect offsetting wells from potential casing collapse, of particular concern in areas with wells of earlier vintage.

The maximum pressure limit is typically calculated based on 120% of the virgin reservoir pressure. A virgin reservoir pressure is the initial pressure tested in the disposal reservoir prior to either production or disposal influence. The virgin reservoir pressure for the well will be supported by tests conducted in other wells in the same or proximal reservoir.

The value of 120% was established based on a review of the discovery pressure of all pools, using examples of pressures above hydrostatic which demonstrated geologic containment. This review excluded over-pressured unconventional self-sourcing shale and tight resources which are not equivalent to targets for storage containment. Unless otherwise stated, the prescribed fill-up pressure is calculated at mid point of perforations, using the perforation interval at the time of issuance of the Section 75 Special Project Order. If the perforation interval changes, the Order must be amended in order to change the perforation interval and the maximum reservoir pressure and maximum wellhead injection will be recalculated.

An initial pressure should be measured in the disposal well prior to injection testing or hydraulic fracture. The test must be submitted to the Commission as part of the application and the results of the measurement must be supported by tests in other wells in the same or proximal reservoir. Where the initial formation pressure measured at the well has been influenced by off-setting production, injection or disposal, or there is poor confidence in the initial test quality, the initial pressure will not be considered a virgin reservoir pressure. In these cases the Commission will utilize a virgin reservoir pressure obtained from a proximal location, adjusted for depth, to calculate the maximum formation pressure limit. When testing the initial reservoir pressure, the Commission prefers a fall-off and/or static gradient test. When a fall-off test is conducted after a DFIT, the permit holder must ensure that the recorders are landed as near as practicable to the perforations and that the shut-in duration is long enough to obtain radial flow.

Most disposal reservoirs are initially under-pressured or normally-pressured for hydrostatic depth. In the case that the reservoir initial pressure, prior to any production or injection, is over normal hydrostatic pressure (>9.8 kPa/m pressure per depth gradient), the maximum formation storage pressure is based on 120% of normal hydrostatic pressure. The creation of a zone of severe over-pressuring around the disposal well is a concern for drillers who may drill through the zone, and for the containment of disposal fluids.

Where wellbore integrity is a noted concern, the maximum formation pressure may be calculated as the value that would limit the hydraulic height of the disposal fluid, at static condition, to below the base of usable groundwater, as determined by the methodology outlined in [INDB 2016-09](#).

Once a well has reached the maximum prescribed formation pressure, disposal must cease. In certain cases, the pressure may fall off below 120% after a prolonged shut-in time; many months or years. In this case, disposal may then recommence until the ultimate fill-up pressure is reached. A well permit holder must demonstrate to the Commission, through reservoir pressure testing, that the pressure has fallen below the maximum formation pressure prior to recommencing disposal operations.

3.5.3 Formation Pressure Monitoring

After the initial reservoir pressure of the disposal formation has been measured, periodic measurement of the reservoir pressure in the disposal well confirms that continued disposal is viable, remaining below the maximum formation pressure limit, and provides information to forecast remaining disposal well life. Typically, annual reservoir pressure testing is required as a condition of the disposal Order. Reservoir pressure tests must be of sufficient quality to extrapolate to stabilized conditions; to predict future disposal capacity based on pressure vs cumulative disposal volume. All reservoir pressure measurements must be reported to the Commission within 60 days of the date of the measurement.

If an annual pressure test shows that the reservoir pressure is approaching the fill-up limit, and a cumulative volume versus pressure extrapolation indicates that the maximum pressure limit will be reached within a year, it is prudent for the operator to schedule the next reservoir pressure test for the predicted date of fill-up, rather than wait for a calendar year to pass. A pressure measurement within 5% of the maximum approved value should initiate an operator review to plan for upcoming well closure.

If the annual pressure test shows that the reservoir pressure has reached or exceeded the fill-up limit, disposal must cease and the Commission must be contacted immediately. In certain circumstances, the well may be approved to continue disposal temporarily while an alternative disposal solution is found. There must be reasonable expectation of continued reservoir pressure dissipation for temporary continued disposal and the Commission will require additional reservoir pressure testing.

Wells that accept fluid at low wellhead pressure, demonstrated to be significantly below the maximum formation pressure limit, may be approved for less frequent reservoir pressure testing. It is noted that wells

with low wellhead pressure values may go on vacuum during formation pressure tests. This can cause downhole effects that may prevent the bottomhole pressure from reaching stability even through pressures appear stable on surface. It is recommended, in some cases, to run a tubing plug when conducting a fall-off test to remove the influence of wellbore dynamics.

A bottom hole pressure calculated using surface pressure measurements is not considered to be of sufficient quality to satisfy the annual reservoir pressure testing requirement. The Commission may accept a surface pressure measurement under special circumstances. Operators must contact the Commission and obtain approval prior to conducting a surface pressure test if they wish it to be considered a valid annual test. A surface pressure measurement reporting a pressure within 5% of the maximum formation pressure will not be accepted and a subsequent test, conducted using bottom hole recorders, will be required.

3.5.4 Pressure Transient Analysis – 60-Day Value

A pressure transient analysis (PTA) of a fall-off test that has achieved radial flow will predict an extrapolated average reservoir pressure P^* value, at infinite time. For the purpose of the disposal condition for reservoir pressure testing, the maximum average reservoir pressure is the pressure measured at the injection well **within 60 days of shut-in** of the well. The well does not need to be shut-in 60 days; a static pressure measurement or fall-off data of sufficient quality for a PTA may be obtained in a shorter time period. The 60-day value provides assurance that the formation porosity and permeability allows fluid to dissipate without creation of a zone of excessive pressure at the injection location.

Experience has shown that disposal wells frequently contact a reservoir storage volume that is smaller than expected from a geologic model based on well control and seismic interpretation. Reservoir compartmentalization may be due to a number of reasons: permeability barriers due to changes in reservoir facies, faults, bitumen plugging, etc. Disposal operation itself is a suspected cause of degradation of reservoir quality for some wells, due to fines migration and scale plugging.

During injection, areas or streaks of high pressure may develop in pockets and layers of higher porosity and permeability (preferential pathways and reservoir). This over pressuring increases the risk that fluid will migrate outside the disposal formation and may present a drilling or completion hazard. Monitoring reservoir pressures and conducting a 60-day extrapolation provides assurance that the pressure will dissipate and the fluid will remain within the disposal formation.

The final pressure limit value, measured at the disposal well, is a proxy for the average pressure in the disposal reservoir. The further into the future the pressure extrapolation, the greater the uncertainty of the value, due to changes in reservoir quality and boundary effects. Fall-off pressure testing of disposal wells with large cumulative disposal volumes in some clastic reservoirs have displayed limited significant pressure drop beyond the initial 60 day shut-in period.

In cases where the rate of change of pressure decline with time (first order derivative) demonstrates continued effective pressure dissipation, a longer extrapolation period may be accepted for demonstrating a current average reservoir pressure that is below the final pressure limit value, allowing continued disposal injection at the well.

3.5.5 Wellhead Pressure Monitoring

Approval Orders contain a condition requiring continuous measurement and recording of the wellhead tubing and casing pressures. Pressures must be measured directly at the wellhead, not the pump outlet. “Directly at the wellhead” can be considered as <10m from the wellhead, and past any restriction (eg. valve, T-connection) where pressure could be restricted. “Continuous” infers sampling and recording values at intervals of one minute or less.

The wellhead pressure measurement device must include a visual display, for recording values during site inspection and comparison to the central control system display value. Pressure sensors must be calibrated as per manufacturer requirement and verifiable by deadweight measurement. The entire system of transmitters, controllers, and visual displays should be calibrated and tested. For example, using a SCADA system, the displayed value in the control room should be compared to the displayed value at the wellhead to ensure that there are no data scaling errors. A preferred system contains set-points with trigger alarms for both operator attention and automatic pump shutdown. Wellhead pressure data files may be requested and audited by the Commission for a period of up to 1 year.

For the tubing, continuous pressure monitoring creates an auditable record that injection has not exceeded the maximum approved value. The MWHIP reported in Petrinex is the maximum wellhead tubing pressure sustained for a period of five minutes or more during the reporting month.

For the casing annulus, continuous monitoring creates an auditable record that wellbore integrity remains intact between periodic packer isolation tests.

Changes in tubing and casing pressures can reveal potential issues for the initiation of remediation work, prior to becoming a more significant problem. An alarm value for wellhead tubing pressure should be slightly below the maximum approved injection pressure to ensure the maximum pressure is not exceeded. An alarm and/or disposal pump shut down for wellhead casing annulus pressure should be incorporated into the injection facility control logic and set at an appropriate value for early detection of loss of hydraulic isolation. The alarm and the shutdown settings should be based on the values observed during normal well disposal operation. Where temperature effects will cause a fluctuation in values. Both high and low alarm values may be appropriate; the design should be for a positive pressure to ensure fluid containment and wellbore integrity.

Approvals stipulate that the operator cease injection and notify the Commission immediately if hydraulic isolation is lost in the wellbore or formation. Loss of hydraulic isolation, such as a suspected packer failure or tubing leak, require disposal operations to cease immediately and not recommence until an investigation of the issue and resulting repairs are complete. 'To immediately cease injection' means to stop pumps and fluid transfer within a matter of minutes, based on disposal facility operation control logic, appropriately set alarm and shutdown set points, or operation intervention while respecting any operational safety and/or environment risks.

Communication between tubing and casing annulus has been noted due to issues with an on/off assembly and packer. In some cases the on/off tool cannot maintain a constant seal, due to changes in downhole conditions between injection periods which causes a cycling effect. When this occurs the removal of the on/off tool is required to eliminate potential hydraulic isolation loss. An alternative is to evaluate the options of equipping the tubing with a compression engagement seal assembly and sting into a permanent packer to set in compression.

The continuous monitoring must be in place while the well is active, and during periods of inactivity. When the well has been downhole suspended in accordance with the [Oil and Gas Activity Operations Manual](#), the continuous wellhead monitoring is no longer required.

3.6 Production Testing

Prior to an injectivity test or disposal operation, the intended disposal zone must be production tested for any hydrocarbon potential. Where a well is incapable of flow to surface, the well must be swabbed down to 80% of perforated depth to ensure no potential hydrocarbon reserves and an uncontaminated formation fluid sample must be taken; the fluid analysis results must be included in the application.

3.7 Wellbore Integrity and Logging

All new wells drilled for the purposes of disposal must ensure that:

- Surface casing is set below the deepest usable water zone and cemented to surface, or
- If surface casing is not set below the deepest usable water zone, the next casing string is cemented to surface, and
- Hydraulic isolation is established between all porous zones. A temperature log is frequently used to confirm hydraulic isolation but other methods may be proposed by the permit holder. Instructions for conducting a temperature log can be found in Appendix E and Section 3.8 Hydraulic Isolation Logging.

All porous zones, in addition to the disposal zone, must be isolated by cement. For all disposal wells, the permit holder must conduct adequate logging to demonstrate hydraulic isolation of the disposal zone. The

preferred cement evaluation/inspection log is a radial log displaying 3' amplitude, 5' VDL and cement map with both a non-pressure pass and pressure pass. Log results and interpretation must be submitted as part of the disposal well application. The Commission refers to the United States Environment Protection Agency [guideline for cement bond logging techniques and interpretation](#). Referring to page 6, the applicant should make note of the continuous interval of >80% bonded cement required to provide hydraulic isolation, based on casing size. If adequate cement bond is not identified, the well may not be suitable for disposal purpose. Permit holders may reference AER Directive 51 for additional logging guidance.

Wellbores with cement squeeze abandonments occurring above the injection zone may not be suitable for disposal service. Cement squeeze abandonments have been prone to isolation failure and it is problematic to demonstrate continued seal when multiple packers are used to isolate former completion intervals. A casing patch might be better suited, however the operator must ensure that annulus communication is maintained throughout the wellbore and that all seals can be adequately tested in this case.

Applications for wells greater than 10 years in age must include new full length casing inspection and cement evaluation logs. A recent log may be suitable if the well has not undergone significant changes since the log was conducted. The casing inspection log should evaluate both internal and external metal loss; a log that consists of only caliper finger results will be considered incomplete. Full length casing inspection and cement evaluation logs to packer depth will be considered if the packer is difficult to remove and if a temperature log can confirm hydraulic isolation.

Once a disposal well is operational, further casing integrity and zonal isolation logging, at specified time intervals, is required to confirm the well remains suitable for continued service use. Casing integrity logs must run the full wellbore. The primary purpose of further logging is to determine the casing condition above the injection zone, especially over the first 600 metres, in order to confirm the protection of groundwater aquifers. The secondary purpose is to ensure that disposal fluids are contained within the approved zone, and to protect up-hole porous zones. Annual packer isolation tests, and hydraulic isolation logs, can show casing failure, but do not allow detection of points of weakness, for example corrosion and metal loss. Casing inspection logs allow for preventative maintenance, and are usually required every 10 years over the disposal life of the well.

The Commission recognizes that in wells which have been operating for a long time, the removal of the packer can be costly, time-consuming, and, in some cases, even damaging to the casing integrity. In these circumstances the Commission will generally accept casing inspection logs which are run to packer depth; these logs avoid risk but provide valuable information. Logs run to packer depth may require release of the packer from tubing using an on-off tool and pulling tubing. In order to avoid pulling tubing altogether, the Commission will accept through-tubing casing inspection logging.

Packer removal may be required where there are downhole porous zones not isolated by packer or bridge plug or if the production packer is not set close enough to the disposal zone, resulting in porous intervals not being logged. Section 16(2)(a) of the DPR requires that production packers be set as near as practical above the injection interval. The Commission expects packers to be set within 15m of the

top of the completed interval in most circumstances, therefore; a casing inspection log run to the depth of the packer should provide reasonable assurance that there is good casing condition down to the proposed disposal zone. Where there are porous zones below the proposed disposal zone, the Commission expects the permit holder to isolate the zones by a packer or a bridge plug. In these situations a packer should be set as close as practicable below the injection interval.

Please Note:

Sumps: sometimes a short sump/cellar (~15 – 30 m) below the base of disposal perforations can be advantageous to operation. Potential uses include: catching debris during flow-back to clean up well damage, space for long tools so that temperature logging will run past the base of perforations, or a place for damaged tools or equipment that may fall into the well during workovers.

The disposal application also requires the casing age, grade and collapse pressure of wells within the area of pressure influence (3km recommended) to be tabulated. These values may be a further limiting factor to the maximum wellhead injection pressure as casing collapse is a concern in the vicinity of disposal wells. An appropriate safety factor must be applied if casing integrity has degraded with age.

3.8 Hydraulic Isolation Logging

Periodic hydraulic isolation logging is also required as a condition of disposal well approvals. A hydraulic isolation log must be run prior to commencing disposal and at condition specified intervals over the disposal life of the well. The log should prove that injected fluids are being contained within the intended zone, as well as possibly identifying leaks above the zone of interest. Typically this log consists of a time-lapse temperature log measured at 0, 30, 60, and 90 minutes after the injection of a cold fluid into the well compared to a baseline. Refer to Appendix E for guidance.

The time-lapse temperature log is a tool for locating zones of injection in the wellbore. However it is limited by distance run (a maximum of 300 metres based on logging time), and temperature interference that may occur due to equipment in the wellbore or reservoir effects. For this reason, a Distributed Temperature Survey (DTS) is preferred. If the temperature log is unclear or a leak is suspected, a radioactive tracer survey may be requested to better pinpoint the area.

Hydraulic temperature isolation logs must be submitted within 30 days of the run date. The submission must include an interpretation report; refer to Appendix E for additional information.

Please Note:

Notable hydraulic isolation log reference papers include:

Smith, R.C., Steffensen, R.J.: "Interpretation of Temperature Profiles in Water-Injection Wells", Journal of Petroleum Technology (June 1975)

McKinley, R.M.: "Temperature, Radioactive Tracer, and Noise Logging for Injection Well Integrity", United States Environmental Protection Agency (July 1994)

3.9 Step-Rate or Mini-Frac Formation Testing

Mini-frac and step-rate testing are direct test methods widely accepted for determining the conditions under which a formation fracture can be created, extended or opened. The Mini-frac or DFIT test is the preferred method for determining the fracture pressure at the proposed disposal site. The test is performed by injecting non-saline (fresh) water into a short section of the wellbore at a single rate, prior to a stimulation operation, until the rock fractures. Injection is typically continued for a few minutes and then the pumps are shut down and the pressure is allowed to bleed off. The ISIP and closure pressures are determined through a DFIT analysis.

However, in some formations the rock may not break. In these situations, a step-rate test can be conducted to establish the formation fracture pressure (FPP), an estimate of fracture pressure. Since the FPP is determined under dynamic condition, friction must be considered when calculating the bottom hole pressure. Also, since the propagation pressure is typically on the order of a several hundred to several thousand kPa greater than the closure pressure (static condition), the value determined from this type of procedure yields an upper bound for closure and may require a higher safety factor in some cases to determine the maximum wellhead injection pressure.

To obtain valid data for determining maximum permissible injection pressure, the step-rate injectivity test must be performed **prior** to fracture stimulation of the formation. A step-rate test is typically conducted by injecting fluid (usually fresh water) into a well in discrete steps of plotting injection pressure against injection rate. The Alberta Energy Regulator has a recommended procedure as show in [Directive 65 Appendix O](#). Also, SPE paper 16798, "Systematic Design and Analysis of Step-Rate Tests to Determine Formation Parting Pressure (1987)" provides detailed step-rate injectivity test information.

3.10 Injectivity Testing (Injection Capacity Testing)

Injectivity testing is conducted to establish the water injectivity potential of the zone of interest. Injectivity testing may not be conducted on open Crown rights, as information provides an unfair advantage in competitive land sales.

An operator may wish to test the water injectivity potential of a zone, prior to testing and completing a well for disposal purposes. Commission approval is required only if the injection test volume will exceed a total of 500 cubic metres, in which case a temporary approval may be granted for the injection test to obtain performance information on the well. An application may be made using the disposal guideline to provide information currently available. Prior to conducting an injectivity, step-rate or DFIT test, a Notice of Operation must be submitted through eSubmission. The injectivity test report, and any other supplemental data, is then submitted to the Commission to complete the application for disposal operation. As well, a completion/workover report in PDF format must be provided to the Commission. As noted in Production Testing above, a pre-test attempt to obtain hydrocarbon inflow must be performed. Reservoir pressure tests both prior to and following an extended injectivity test can provide insight to the storage capacity of the reservoir.

3.11 Perforations

A permit holder may add perforations to a formation approved for disposal without prior approval from the Commission. The permit holder must submit a request for amendment to the Reservoir Engineering Department when the perforations increase the gross completed interval (GCI). Extension of the GCI requires an amendment to reflect the new depths of the interval, new MPP and maximum formation pressure. Extension of the GCI to a shallower depth will also result in a re-calculation of the maximum wellhead injection pressure.

In some circumstances the Commission recognizes different formation tops than permit holders. This may result in new perforations being classified occurring in a separate formation and completion event. Permit holders may submit proposals for additional perforations to the Commission for review in advance if they wish to confirm the formation(s).

3.12 Hydraulic Fracture Stimulation

A completed wellbore interval may require an acid or hydraulic fracture stimulation to bypass formation damage caused by well drilling/cementing operations and to increase connectivity. Approval Orders for disposal wells include a condition prohibiting future hydraulic fracture stimulations without prior approval. This condition does not apply to hydraulic fracture stimulations of limited size (< 5T), designed only to remove near-wellbore accumulated damage such as scale or fines.

Advance permission from the Commission must be granted before a hydraulic fracture stimulation is conducted in a well where disposal has occurred, other than described above. Permit holders must submit, to the Reservoir Engineer Department, a fracture plan that includes the intended size and maximum treating

pressures, together with results from fracture simulation software. It is imperative that the hydraulic fracture treatment does not result in loss of integrity of bounding formations as required by Section 22 of the Drilling and Production Regulation. The Commission may require additional tests and data to confirm isolation and integrity of the bounding formations following the stimulation. An outcome of loss of formation isolation may result in cancellation of the disposal approval and, where a risk to the environment, safety or resource recovery occurs, remedial action, including formation fluid flow back, may be required.

3.13 Horizontal or Highly Deviated Disposal Wells

Disposal into wells that are horizontal or highly deviated in the disposal zone may be considered by the Commission. Extra factors must be considered for these types of wells. Full-length integrity logs are expected for disposal wells (CBL, casing inspection, temp log), which may pose difficulties in horizontal wells. For example, temperature logs can be run normally to point of wireline refusal, which may be a significant vertical distance above the zone of interest. In certain cases the Commission may require distributed temperature sensing in order to log the entire wellbore. The packer set depth may be an issue based on the limitations of the angle of inclination. It is expected that the packer will be set as close as practicable above the top of the disposal zone, which requires consultation with the Commission where this is not possible in a highly deviated well. If the zone is hydraulically fracture stimulated, care must be taken to ensure that the stimulation remains in-zone.

3.14 Seismicity

Some disposal wells have been linked to induced seismic events. Applications are reviewed for induced seismicity potential, based on identified faults and the history of induced seismicity in the area associated with the disposal into the proposed formation. Induced seismicity may be expressed in formations other than the disposal formation, often a deeper formation. Applications have been denied due to the risk of induced seismicity.

A demonstrated pattern of cause and effect to disposal operations may result in modification to the disposal approval, limiting injection pressure and/or rate to mitigate further seismic activity, or may require ceasing disposal injection. An array of seismometers may also be ordered by the Commission to closely monitor event locations and depths.

Section 21.1 of the Regulation requires reporting to the Commission any seismic events with magnitude 4.0 or greater, or felt ground motion, within 3km of an operating disposal well. Disposal operation must be suspended if the seismic event of magnitude 4.0 or greater is attributed, by either the well permit holder or the Commission, to the operation of the disposal well.

3.15 Packer Isolation Testing

Annual packer isolation tests must be conducted in accordance with Section 16(3) of the Drilling and Production Regulation. The test must follow the procedures outlined in Section 9.1.3 of the [Oil and Gas Activity Operations Manual](#). Continuous monitoring of casing and tubing pressure is considered the primary wellbore integrity detection method. The annual packer isolation, considered a secondary level of integrity detection, is only conducted up to 1,400 kPa.

Please Note:

Before water disposal operations begin, a pressure integrity test must be conducted. This is the standard pressure testing requirement when any completion or workover is conducted and is not the same as a packer isolation test. In a pressure integrity test the casing or casing/tubing annulus is pressure tested to a minimum pressure of 7,000 kPa for 10 minutes prior to the commencement of injection or disposal operations (see Chapter 9 of the [Oil and Gas Activity Operations Manual](#) requirement for activating suspended wells and suspending wells). A pressure test is considered successful if the pressure does not vary by more than three per cent during the test period.

3.16 Groundwater Monitoring Requirements

Disposal well sites have a potential for surface spills due to large volumes of wastewater being handled at the site over long time periods. A permit holder must prevent spillage, promptly report and remedy spillage that occurs, and remediate land or water affected by the spillage (refer to OGAA Section 37). Permit holders must also ensure that there is no contamination of water supply wells and usable aquifers due to activity (refer to Drilling and Production Regulation Section 51(1), and Environmental Protection and Management Regulation Section 10 for Crown land). Disposal well operators are expected to maintain and manage the area surrounding the wellhead to prevent shallow aquifer contamination. This may be especially important when the well does not have cement to surface on the production casing, providing a pathway for fluids.

All disposal wells undergo a review by the Commission's Reservoir Engineering, Geology, Drilling Engineering, and Hydrogeology staff. The review includes a hydrogeological risk review that considers well construction and reservoir integrity information in relation to an assessment of groundwater sensitivity. As part of the disposal application, an applicant can use the following reference to provide details about the groundwater in the area: ([BC OGC Groundwater Review Assistant](#)). For disposal well applications that are approved, the approval Order contains standard conditions for well monitoring and reservoir protection, and, based on the hydrogeological risk review, may also include conditions for the protection of groundwater. In some cases, disposal well applications may be denied based on the hydrogeological risk review.

The hydrogeological risk review involves compiling summary documentation on: disposal well information and construction details; disposal interval; an assessment of the base of usable groundwater (using the “geological marker based approach” which applies the definition of “deep groundwater” from the BC Water Sustainability Act, outlined in [IB 2016-09](#)); well testing and logging data; relevant geological formation information; reservoir information; and a desktop hydrogeological review to document proximity to water supply wells, aquifers, capture zones, surface water bodies, surrounding land usage/occupancy, or other available information to assess groundwater use sensitivity. A risk-based approach is used to determine whether groundwater monitoring requirements are appropriate to address concerns, and if so, the Commission Hydrogeologist uses the documented information to develop well-specific recommendations for groundwater monitoring, included as an Appendix within the Section 75 Special Project Approval Order.

The implementation of a groundwater monitoring program involving the installation and testing/sampling of one or more dedicated groundwater monitoring well(s) is required for disposal wells if:

- concerns regarding wellbore integrity and/or groundwater sensitivity are identified; or
- the top of the disposal zone is below, but within 100 m of, the Base of Usable Groundwater (as determined by Commission Geology staff using the “geological marker based approach” which applies the definition of “deep groundwater” from the BC Water Sustainability Act as outlined in [IB 2016-09](#)). (If the top of the disposal zone is shallower than the base of usable groundwater determination, applications will be denied.)

The above framework is applied allowing for professional judgment by Commission staff. Specific requirements relating to the number of monitoring wells, locations, depths, sampling frequency, analytical parameters, and reporting will be determined by the Commission on a case by case basis, based on well and site-specific information.

Please Note:

Groundwater monitoring wells are used for evaluation or investigation of groundwater chemistry conditions or hydrogeological conditions. Groundwater monitoring wells are typically installed using water well drilling methods (e.g., auger drill, air rotary drill). A small diameter (e.g., 5 cm) plastic (PVC) pipe, equipped with a slotted section to permit groundwater sampling, is placed into a drilled borehole, backfilled, sealed near the ground surface (e.g., with cement or bentonite), and capped as per requirements of the BC Groundwater Protection Regulation. Monitoring wells may extend to a range of depths depending on their purpose, with many less than approximately 30 m deep as they are intended to allow for sampling of relatively shallow groundwater. Groundwater monitoring wells are typically strategically located, drilled, and constructed with consideration of their purpose and as directed by a Qualified Professional. Further information regarding groundwater monitoring may be found in Section entitled “Groundwater Pollution Monitoring” pages 268-299, Part E, of the complete [BC Field Sampling Manual](#) (2013).

3.17 Facilities

A separate facility application must be submitted to the Commission for surface equipment associated with a disposal well.

3.18 Disposal Fluids

The Commission does not specify or restrict the location or formation source of produced or flowback water that may be disposed into the well. It is the expectation of the Commission that the well operator will follow good practice in regard to compatibility and treatment of water prior to disposal in order for the disposal formation to continue to be viable for disposal and as a potential future saline water source zone, where practicable.

The Commission encourages operators to sample and analyze disposal fluids and consider their compatibility with the disposal formation. Significant study and ongoing diligence is required in the areas of disposal water chemical treatment, filtration and wellbore maintenance to ensure continued predictable operations. The tubing, perforations and reservoir permeability all benefit from attention to the details of water treatment prior to disposal.

3.19 Sour Water Disposal

The H₂S content of disposal water is limited by the H₂S concentration permitted at the facility. Permit holders are required to permit a disposal facility at the maximum H₂S concentration of the source battery, plant or well. Typically, a disposal facility is initially permitted at a quite high H₂S concentration in anticipation of a number of different sources. If a disposal facility agrees to receive fluid from a new source with higher H₂S, an amendment to the disposal facility approval would be required. The disposal facility permit therefore limits the H₂S allowed in the produced water.

The H₂S in solution could at times exceed the H₂S designation at a facility, especially at a gas facility where the H₂S concentration is typically determined from a gas stream source at the inlet of the facility after separation. However, the H₂S in solution normally involves very small quantities of gas, and therefore doesn't impact the ERP, but is a condition that must be monitored when the fluid is agitated and can flash off gas. When H₂S may flash off, consideration must be given for: odour control from tank venting, worker safety, and truck loading operational procedures. This increased H₂S concentration should also be considered in the determination of a maximum H₂S concentration at the disposal station.

For example, if an oil battery is permitted at 2% H₂S, and produced water was being trucked from this battery to a disposal station, the station must be permitted at the threshold of at least 2% H₂S. This will ensure the following:

- adequate consultation and notification has been completed,
- ERP is sufficient and is consistent with the risks at the facility,
- piping and equipment design and materials are fit for sour service,
- facility design will ensure no off-site odours with associated venting, etc.,
- sufficient H₂S detection devices installed if required by the regulation.

A threshold limit for disposal of sour water is not normally specified within the OGAA Section 75 approval order. Reservoir considerations for sour water disposal require consideration of sour service rating of wellbore equipment, and that of wells which may be contacted via reservoir fluid migration. Hydrogen sulfide, when dissolved in water, is a corrosive weak acid which may cause metal pitting or scaling. High pH values of the disposal water will inhibit the H₂S effect. Operators can refer to Section 7.2.1.2 of NACE0175/ISO15156 for a chart that shows the severity of the sour environment based on pH and H₂S partial pressure, in order to determine what type of sour service equipment is required. Sour water disposal must also consider any potential contact with sweet production, or potential future reservoir use as a deep water source.

3.20 Notification and Reporting

The quantity and rate of fluid injected into a well must be metered, as per Section 74 of the Drilling and Production Regulation.

For each month during which water is disposed into the well, disposal data, total injection hours, volume and maximum wellhead tubing injection pressure, must reported in Petrinex. Disposal data must be submitted by the 20th day of the month following injection.

If the disposal well is not anticipated to be utilized for a period of one year or more the status should be updated to “Suspended”.

A change in operations, such as at start-up or a rate change, can result in momentary pressure spikes. The wellhead pressure reported in Petrinex is the maximum pressure, sustained for a period of a minimum of 5 minutes continuous duration, experienced during the reported month.

3.21 Abandonment

Abandonment programs are subject to Commission review and approval. At the time of abandonment, the disposal formation pressure may be elevated above the initial formation pressure. Abandonment requirements may be elevated to Level A, as per AER Directive 20 “Well Abandonment,” if the reservoir pressure is excessive (above hydrostatic) or well integrity is compromised.

A final reservoir pressure is required prior to abandonment and after final disposal operations, to confirm the final formation pressure resulting from the disposal operations. The test ensures formation pressure has not exceeded or will dissipate below to the maximum formation pressure approved. The final reservoir pressure will also provide a valuable data point to be used for any future work in the area (such as drilling or recompletions) or on the well. A copy of the reservoir pressure test must be submitted to the Commission within 60 days of the end of the test or at least seven days prior to abandonment; whichever is lesser.

3.22 Approval Termination

Approvals for wells that have been surface abandoned are automatically cancelled. If an operator plans to re-enter a previously surface abandoned disposal well for disposal use into the same formation, a new application must be made.

Disposal wells that have been inactive or suspended for a significant period of time will be reviewed for potential disposal approval cancelation as the designation is considered “spent”.

Section 75(2)(b) of OGAA permits the Commission to cancel, suspend or amend a disposal approval for reasons of public safety, protection of the environment or conservation of oil and gas resources.

Chapter 4: Dual Water Source and Water Disposal

Several wells, notably completed in the Debolt formation in the Horn River Basin and the Paddy-Cadotte formation in the Sunrise Field (Montney play), utilize the same interval as both a water source and for disposal. Additional formations in other areas may be suitable for this usage. The Commission encourages practices and technology that minimize surface impacts and minimize withdrawals from potable water sources. Large water management projects, referred to as water hubs, involving multiple wells with alternating or dedicated source, disposal and recycling operations, should be presented to the Commission's Reservoir Engineering department with disposal applications. Such information is valuable to the determination of conditions for source and disposal approvals.

The normal requirements for licensing and seeking an approval order for a disposal well apply to wells that will have dual source/disposal operation. The well type will be the initial usage with changes from source to disposal or disposal to source operations requiring status changes in Petrinex.

Disposal fluid may require treatment to ensure that reservoir "souring" does not occur as a result of biogenic processes, to minimize later safety and cost requirements.

Chapter 5: Commingled Disposal

Unsegregated disposal into more than one zone in a wellbore may be considered by the Commission. Access to more than one zone can improve well disposal capacity while minimizing surface disturbance. Allocation factors, for the reporting of monthly disposal volumes to each formation, are based on comparative reservoir qualities of thickness, permeability and porosity, and the results of any well testing, such as injectivity tests and temperature logs or spinner log surveys.

Each zone must be tested separately for disposal application parameters (fracture pressure, reservoir pressure). The maximum reservoir pressure and maximum wellhead injection pressure limits in the approval will be based on the most conservative numbers for fracture gradient and initial reservoir pressure, which come from the upper zone. If the formations are close together, the well may be approved for unsegregated disposal into both zones, with a packer set atop the upper zone. In this case the Commission may set a limit to the amount of time that the zones can remain open to each other during downtime, to prevent cross-flow. Depending on the depth and vertical separation of the zones, and the presence of potential fluid receptor zones in between the disposal zones, segregation during disposal may be required. This may introduce limitations to the system, including the ability to perform annual segregation testing and continuous casing monitoring. In this case, more frequent testing (packer isolation testing, hydraulic isolation logging) may be required to ensure fluids are contained to the approved formations.

In some cases, for the purpose of simplified disposal operation and testing, the Commission will designate multiple zones as a single compound formation, such as the Paddy-Cadotte, where this still supports appropriate reservoir management.

Chapter 6: Performance Monitoring

Similar to performance monitoring of producing wells, in order to forecast rate and ultimate cumulative volume, and to identify well performance issues that may require remediation, it is recommended that operators track ongoing injectivity performance of disposal and injection wells. A plot of the parameters of hourly rate/wellhead injection pressure (m³/hr/kPa) vs Cartesian time scale will normally indicate a continued loss in injectivity over time, due to such factors as fines migration, scale precipitation and reservoir fill-up.

Requirements for monitoring of water source wells are outlined in the Supplementary Information for Water Source Wells document.

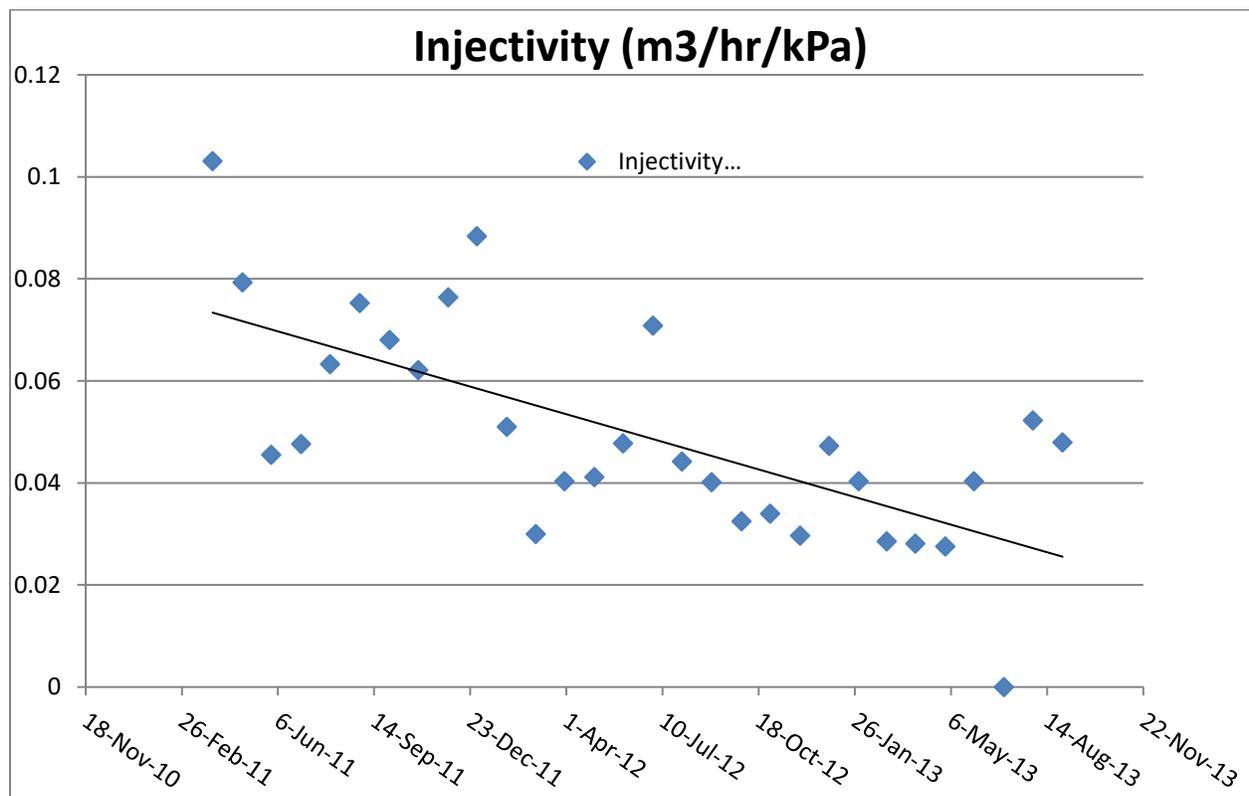


Figure 1 Example injectivity plot

Appendix A: Calculating Maximum Well Head Injection Pressure

$$P_{\text{Wellhead}} = [P_{\text{ISIP}} \times 0.9] - P_{\text{Hyd}} + P_{\text{Friction}}$$

P_{ISIP} = bottom-hole formation fracture pressure (kPa), derived from;

- Initial post-frac ISIP value of fracture stimulation of disposal formation, subject well or close proximity, **or**
- Step-rate injection test on disposal formation, subject well or close proximity, **or**
- Interpolated from [Commission Formation Fracture Gradient](#) maps.
- Calculated to true vertical depth to top of perforated interval (mCF + 1 m reference). For ISIP or step-rate test, use density of fluid in well bore at time of event to extrapolate pressure to depth.

0.9 = a 10% safety factor is applied.

P_{Hyd} = Hydrostatic pressure (kPa) of disposal fluid column in well bore.

- Assume minimum gradient of 10.5 kPa/m, to account for potential high TDS fluids.
- Height of true vertical depth to top of perforated interval (mCF + 1 m reference).
- Table listing water salinity versus gradient can be found [here](#)

P_{Friction} = Frictional pressure loss (kPa)

- Use chart below to find frictional pressure loss based on tubing diameter and expected maximum flow rate. (Because disposal rates vary considerably, friction losses also vary. The Commission uses a conservative friction loss value of 200kPa for calculation of wellhead injection pressure)

Other Notes:

- Formation fracture pressure is based on an average of area values where possible, due to the potential for an individual well anomalous value.
- Injectivity tests conducted on wells that have had previous fracture treatments are deemed questionable as it is inferred that the conductivity of the fracture distorts the results with the limited volumes used during testing.

Example:

Depth to top perforations: 1137.0 m (1136.0 mCF + 1m above ground level)

Fracture gradient = 25 kPa/m (from Commission contour maps)

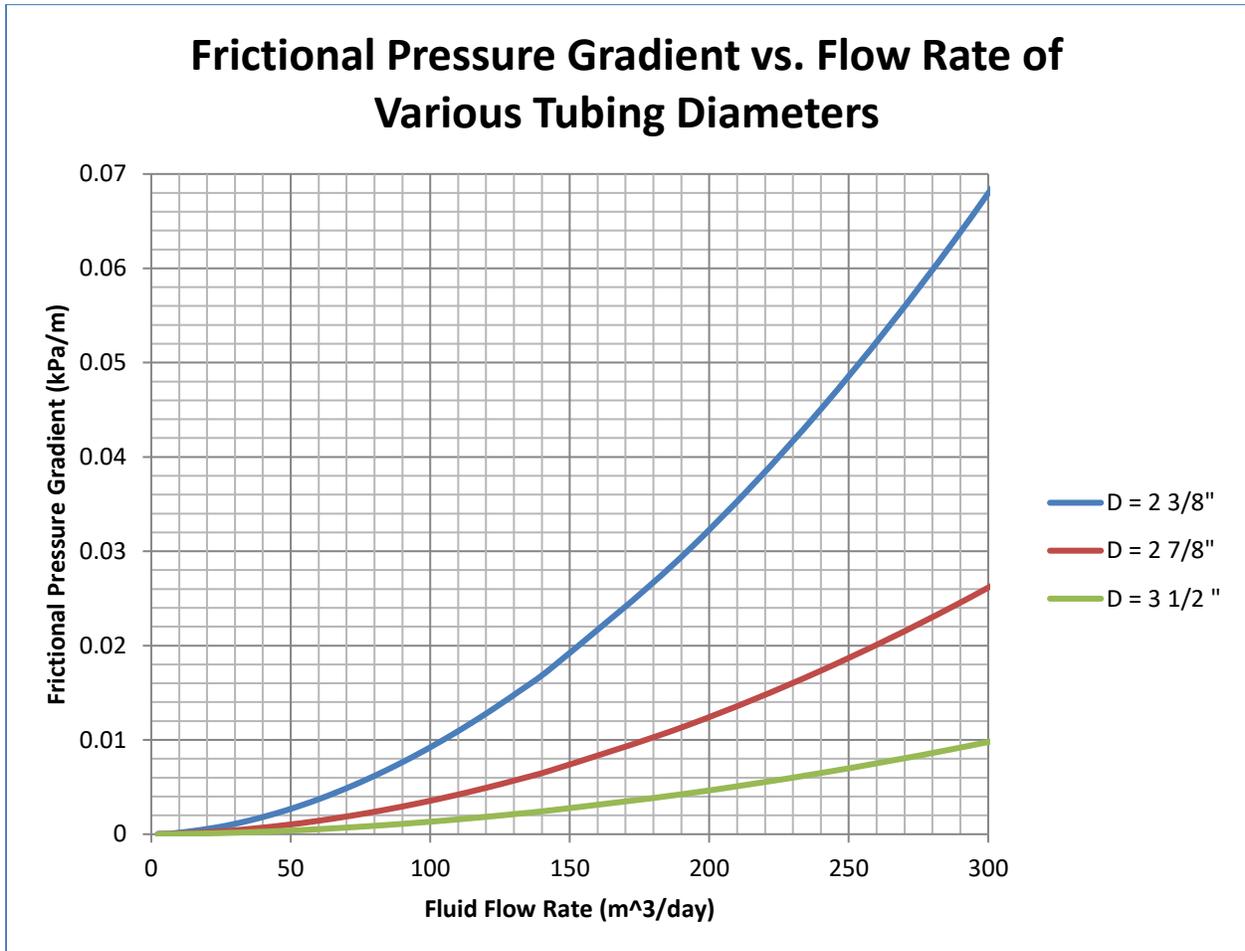
$P_{\text{wellhead}} = [25 \text{ kPa/m} * 1137.0\text{m} * 0.9] - (10.5 \text{ kPa/m} * 1137.0\text{m}) + 200 \text{ kPa}$

$P_{\text{wellhead}} = 25,582.5 - 11,938.5 + 200$

$P_{\text{wellhead}} = 13,844 \text{ kPa}$

The maximum wellhead pressure will be 13,840 kPa.

Appendix B: Colebrook-White Friction Pressure Loss



Appendix C: Well Testing Process Prior to Application

Recommended process to gather application data:

- Conduct a radial cement bond log displaying 3' amplitude & 5' VDL from the shoe to surface and then again with a 7000kPa pressure pass.
- If well is more than 10 years old, conduct casing inspection log (MIT/MTT tool).
- Conduct baseline temperature pass.
- If this is a new disposal zone, perforate zone.
- Swab to 80% of depth to test for hydrocarbon production. Collect representative formation water samples, once load fluid volume recovered.
- Have water samples sent off for analysis and compatibility testing with disposal fluids.
- Run final string into the well, set packer as close as possible to the top of the open hole/casing shoe.
- Run recorders to obtain initial reservoir pressure and conduct the step-rate test or mini-frac to obtain formation fracture gradient.
- Rig out and come back after two weeks to pull the recorders
- Conduct concluding temperature logging following injection test to confirm zonal isolation of fluid.

Appendix D: Summary Table

Well Type	Well Permit Req'd	Tenure or Consent Req'd	Target area applies?	Section 75 Approval Req'd	Applicable Well Spacing	Monthly Reporting	Links
Water Source	Y	N (unless hydrocarbon produced)	N	N	none	Petrinex	Oil and Gas Activity Application Manual Summary Information for Water Source Wells document.
Water Injection	Y	Y	N	Y	none	Petrinex	Pressure Maintenance or Improved Recovery
Water Disposal	Y	Y	N	Y	none	Petrinex	Deep Well Disposal of Produced Water

Consultation Considerations:

Notification and consultation with surrounding subsurface tenure owners or well operators regarding reservoir projects is not a statutory requirement; however is a highly recommended practice to mitigate potential objections during the application process.

For subsurface regional disposal aquifers, the recommended consultation radius is three km. This may be modified to accommodate geological trends controlling the area of influence.

For disposal into a mapped semi-depleted hydrocarbon pool, all completed wells in the pool should be considered.

Policy on reservoir project application notification and objections is available [here](#).

Appendix E: Hydraulic Isolation Temperature Log

This Appendix provides guidance for conducting a hydraulic isolation temperature log used to evaluate hydraulic isolation of the disposal or injection zone. These guidelines may not be appropriate for all wells. The permit holder is responsible for ensuring the log collects good quality data to demonstrate hydraulic isolation.

Injection fluid should differ by **at least 15°C** from the current reservoir temperature of the injection zone. The greater the temperature differential the more reliable the log will be. Conducting the log during winter conditions, when the ambient temperature will cool the injected water, is recommended. The fluid should be injected with a bottom hole injection pressure as close to the normal operating pressures as possible. The volume injected must be sufficient to ensure the fluid has reached and is injected into the open zones. A volume no less than 15 m³ is recommended.

The well must be shut-in for at least 12 hours prior to obtaining a baseline profile. The duration of shut-in required to achieve a definitive result may vary depending on operating parameters and the disposal formation. It is the responsibility of the permit holder to ensure the shut-in time is adequate. Indeterminate results will require re-logging of the well.

Typical Testing Procedure

- Shut-in the well and do not inject for a minimum of 12 hours.
- Run baseline temperature profile.
- Inject at least 15m³ of fluid, **at least 15°C** cooler than the current temperature of the injection zone, at a bottom hole pressure as close as possible to normal operation conditions.
- Obtain four temperature profiles at 30 minute intervals, with the first occurring **immediately** after injection (i.e. 0 minutes).

Please Note:

Based on a tool run time of ~10m/min, there may be a limit to the distance that can be logged. For this reason, **Distributed Temperature Surveys are preferred** – especially if there is any question regarding well integrity.

If running a standard four pass log, the log (including the baseline log) should be run from at least 200 metres above the injection zone to just below the base of perforations. When a Distributed Temperature Sensing (DTS) system is used, a continuous temperature profile from baseline profile to 90 minutes after injection should be collected and timed snapshots presented on the log. The DTS system should log the entire wellbore profile.

A radioactive tracer survey is acceptable as an alternate to a temperature log to demonstrate hydraulic isolation.

Log Submission

An interpretation with the following information **must** be included in the well log submission:

- The duration of shut-in prior to conducting the log.
- The operating/stabilized rate of injection prior to shut-in.
- The operating/stabilized injection pressure prior to shut-in.
- The temperature of the fluid injected.
- The volume of fluid injected.

The log must be presented as a composite overlay, including base line and the timed snapshots (or passes), on the same axis for comparison. The scale for temperature should be consistent for all snapshots (or passes) presented.

- Where available, a comparison to the baseline temperature profile obtained prior to any injection should also be provided.
- Profiles should be presented at a scale of 1:240 metres and a more compressed scale, such as 1:1200 metres.
- The location of the packer and perforations must in be presented.
- An LAS file of the raw data must be submitted.

Well log submissions must be made to the Commission within 30 days of the run date.