

Water Service Wells Summary Information

October 2017
Version 2.6



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Table of Revisions

The Commission is committed to the continuous improvement of its documentation. The table below summarizes revisions to the Water Source, Injection and Disposal Service Wells Summary Information. Revisions are posted to the documentation section of the Commission's website at the beginning of every month and are effective one month after posting, unless otherwise noted. For more information about the Commission's monthly revisions, and for details of this month's revisions, please visit the documentation section of the Commission's website.

Stakeholders who would like to provide input or feedback on Commission documentation may send comments to OGC.Systems@bcogc.ca.

Posted Date	Effective Date	Chapter	Summary of Revision(s)
September 8, 2016	October 1, 2016	Various	Various updates have been made to this document. Users are encouraged to review the document in full. Sections of change include: Disposal Well Approval Application, Formation Pressure Monitoring, 60-Day Pressure Value, Wellhead Pressure Monitoring, Wellbore Integrity & Logging, hydraulic Isolation Logging Seismicity, Groundwater Monitoring Requirements, Sour Water Disposal and Abandonment.
June 7, 2017	July 1, 2017	Various	Various edits have been made to this document. Sections to note include: Disposal Well Approval Application, Wellbore Integrity and Logging, Horizontal or Highly Deviated Disposal Wells, Groundwater Monitoring Requirements, Sour Water Disposal, and Commingled Disposal. Users are encouraged to review the document in full.
October 3, 2017	November 1, 2017	Various	Various changes have been made to this document. Users are encouraged to review the document in full. Sections to note include: Clarifications in Permit section (page 11); changes to the wellbore integrity and logging section (pg 16) (1 deletion, 1 addition); additions to the Abandonment section (pg 24), and a new Approval Termination section (pg 24).

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Preface

This document provides guidance regarding storage reservoir management and the regulation of disposal wells, injection wells, and water source wells. The focus of this document is on deeper confined aquifers that have the potential to be used conjunctively for water disposal, injection, and water sourcing and may be hydrocarbon producing.

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.

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.

This document is not intended to take the place of the applicable legislation. The user is encouraged to read the full text of applicable regulation and seek direction from Commission staff, if and when necessary, for clarification.

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.

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](#).

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.

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 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.

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.

Notification and Reporting

The form BC-11, [Notice of Commencement or Suspension of Operations](#), must be submitted to the Ministry of Finance by the 20th day of the month following the date of initial water production, informing of date of initial operation.

For each month during which water is produced a, BCS-1 (Monthly Production) Statement and a BC-S2 (Monthly Disposition) Statement must be filed with the Ministry of Finance, reporting producing hours and volume. Check here for more details: <http://bcogc.ca/industry-zone/documentation/Subsurface-Disposal>.

If the water source well event is not linked to a facility, a facility code must be obtained by the operator prior to submitting a BC-S1/BC-S2. To do this, the operator must contact the Commission's Facility Department.

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

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](#).

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.

Well Classification, Spacing and Tenure

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 $\frac{1}{4}$ 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). However past experience has shown that such wells generally benefit from increased oil recovery.

Wellbore Integrity and Logging

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 are not maintained during setting, a log must be run to locate the cement top in addition to the required hydraulic isolation logging. For all injection wells, the permit holder must conduct adequate logging to demonstrate hydraulic isolation of the injection zone and all porous zones. Permit holders may reference ERCB Directive 51 for logging guidelines. 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

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

- 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. Often a temperature log is the method used to confirm hydraulic isolation but other methods may be proposed by the operator. Instructions for conducting a temperature log can be found in the AER Directive 51 Appendix 2.
- Wellbores containing uphole zones with cement squeeze abandonment may not be suitable for injection service. Experience has shown that cement squeeze abandonments may be prone to isolation failure. The use of multiple packers to isolate former completion intervals in the wellbore is problematic to test for continued seal. Application for injection service for a well with uphole former completion intervals must adequately address this concern.

For wells greater than 10 years in age, the injection well application requires a full length casing inspection and cement evaluation log. Full length casing inspection and cement evaluation logs may be acceptable up to packer depth if the packer is difficult to remove and if a temperature log can confirm hydraulic isolation.

Conducting a full length casing inspection log typically requires removal of the tubing and production packer. In wells that 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 order to avoid creating more risk but still add value, the

Commission will generally accept casing inspection logs run down to the packer depth. This may consist of releasing packer from tubing using an on-off tool and pulling tubing. In order to avoid pulling tubing altogether, the Commission is also accepting through-tubing casing inspection logging.

Packer removal may still be required if there are downhole porous zones not blocked off by packer or bridge plug or if the production packer is not set close enough to the injection zone (ie there are porous intervals that would not be logged). Section 16(2)(a) of the Drilling and Production Regulation states:

A well permit holder must: set a production packer in the well as near as is practical above the injection interval.

For the most part, the expectation is that operators will follow the above regulation, which is expected to be within 15m or the top of the completed interval. Therefore a casing inspection log down to the depth of the packer should provide reasonable assurance that there is good casing condition down to the zone of interest. Additionally, it is the expectation of the Commission that wells with porous zones below the zone of interest have those zones blocked off, either by a packer or a bridge plug. Again, in these situations there should be a packer set as close as practicable below the injection interval.

The pressure maintenance 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 an injection well. An appropriate safety factor must be applied if casing integrity has degraded with age.

Pressure Monitoring

Injection pressure must not exceed the formation fracture pressure, and recommended practice is to not exceed 90 per cent of this value. Any changes to injection fluid density, usually due to salinity, must be accounted for. Injection above formation fracture gradient may lead to over-pressuring of formations above and below the completed formation, a well drilling and operating safety hazard, and a potential loss of producible hydrocarbons.

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.

Packer Isolation Testing

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

Annual packer isolation tests must be conducted in accordance with Appendix D of this document. 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.

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. Once a well has been granted injection approval by the Commission, the approval Order includes a condition prohibiting future hydraulic fracture stimulations. 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.

Permit holders are cautioned to design and limit fracture stimulations to remain contained within the injection formation. If planning a fracture stimulation post disposal initiation, submit to the reservoir engineering department a fracture plan that includes the intended size and maximum treating pressures, together with results from fracture simulation software. Where it appears there is significant potential that the induced fractures, and thus pathways for disposal fluid migration, has occurred out of zone, the Commission may require additional tests and data to confirm isolation and integrity of the bounding formations.

Facilities

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

Notification and Reporting

The form BC-11 Notice of Commencement or Suspension of Operations must be submitted to the Ministry of Finance by the 20th day of the month following the date of initial injection, informing the date of initial operation.

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

For each month during which water is injected into the well, the form BC-S18 Monthly Injection/Disposal Statement must be filed, reporting total injection hours, volume and wellhead tubing pressure. The BC-S18 is due by the 25th day of the month following injection. Should the well operate seasonally or be shut-in temporarily, continue to submit monthly S-18 Injection/Disposal reports, with values of zero "0" for volume, pressure and hours. This verifies that well is temporarily inactive, avoiding flagging for potential reporting noncompliance. Since April 2015 this form is filed via the Commission's e-Submission portal. Both the [form](#) and [instructions](#) are available on the Commission website.

A change in operations, such as at start-up or a rate change, can result in momentary pressure spikes. The BC-S18 reported wellhead pressure is the maximum pressure, sustained for a period of a minimum of five minutes continuous duration, experienced during the reported month.

If the disposal well is not anticipated to be utilized for a period of one year or more, submit a BC-11 form changing status from "Active" to "Suspended". Once changed to Suspended, cease submission of S-18 reports.

Water Disposal Wells

Water produced in association with oil and gas 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 > 800 meters below ground level.

Deep Disposal Options

- i. **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, approval has been granted to dispose water into a producing pool below the gas/water or oil/water contact, where it can be demonstrated that disposal will not be detrimental to ultimate pool hydrocarbon recovery.
- ii. **Deep aquifers** - contain water of high salinity trapped underground for millions of years, at a variety of depths. 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 faulting. 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.

Disposal formations must be shown to be contained by impermeable cap and base formations, competent to contain fluid within the area of influence. With 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.

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

Submit Notice of Operation to the OGC prior to work on well

<http://www.bcogc.ca/node/5753/download>

Application for deep well disposal service, 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>

Submission of form Notification of Commencement or Suspension of Operations (BC-11) to Finance once injection begins, that triggers change of well status to active disposal

http://karpo.gov.bc.ca/royp-bin/phcgi.exe?PH_QKC=BC11_C1&PH_APP=RMSprodApp&PH_HTML=BC11_C1.htm

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. A disposal well permit holder is required have registered ownership, or consent from the owner, 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.

Disposal Well Approval Application

The Commission guideline [Deep Well Disposal of Produced Water](#) provides a comprehensive listing of the information for inclusion in an application. Two copies of the application, in hardcopy format, must be submitted to the Commission's Reservoir Engineering Department in Victoria, with a third copy submitted to the Drilling and Production Department in Kelowna.

For the purposes of defining disposal fluids, produced water includes recovered fluids from a well completion or workover operations (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** 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 guide may be found at [Deep Well Disposal of Non-hazardous Waste](#). 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:

a) Maximum wellhead injection pressure

- i. 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 10.5 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 11.5 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 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, a well drilling and operating safety hazard, and a 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 2 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 the **Step-Rate or Mini-Frac Formation Testing** section below for information addressing direct testing for formation fracture pressure.

b) Maximum formation pressure

Disposal well approvals contain a condition limiting the ultimate formation “fill-up” pressure to a specific value. This pressure limit is typically calculated based on 120% of the virgin reservoir pressure, prior to any production or injection within the reservoir. Unless otherwise stated, the prescribed fill-up pressure is calculated at mid point of perfs, 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. A recalculation will also be done for maximum reservoir pressure and maximum wellhead injection pressure at that time.

This virgin pressure is initially tested in the disposal well and is supported by tests in other wells in the same or proximal reservoir. 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 120% limit is also a measure to protect offsetting wells from potential casing collapse, of particular concern with area wells of earlier vintage.

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 re-commence until the ultimate fill-up pressure is reached.

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](#).

c) Formation Pressure Monitoring

The initial reservoir pressure of the disposal formation in the well must be measured and reported. 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. Despite the minimum expectation that tests verify current pressure remains below the ultimate limit, it is highly recommended that reservoir pressure tests be of sufficient quality to extrapolate to stabilized conditions, to predict future disposal capacity, based on pressure vs cumulative disposal volume.

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.

If the annual pressure test shows that the reservoir pressure has exceeded the fill-up limit, the Commission should be contacted immediately. Once the pressure is analyzed and verified, the Commission will expect disposal to cease into the well. In certain circumstances, the well may be approved to continue disposal temporarily while an alternative disposal solution is found.

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 to run a tubing plug when conducting a fall-off test, to remove the influence of wellbore dynamics.

d) 60-Day Pressure 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 this disposal condition, 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, if the pressure drops below the reservoir pressure limit value in a shorter time period, or if fall-off data is of a quality that PTA can confidently extrapolate to a 60-day shut-in value. 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.

While the wellhead injection pressure limit prevents formation fracture breach, injection operation can develop an area significantly above the final maximum formation pressure limit. Examples have shown that this zone of high pressure may be stored in a high permeability streak extending some distance from the disposal well. Assurance is required that this pressure will dissipate within the disposal zone. The higher the pressure, and longer the time to dissipation, increases the potential for fluids to find pre-existing migration pathways outside the injection zone, as well as remain a high pressure drilling or completion hazard.

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.

e) Wellhead Pressure Monitoring

Approval Orders contain a condition requiring continuous measurement and recording of the wellhead tubing and casing pressures. As stated, 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 1 minute or less. The wellhead pressures measurement device must include a visual display for recording values during site inspection. 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 monitoring creates an auditable record that injection has not exceeded the maximum approved value. The MWHIP on the monthly BC-S18 form is the maximum wellhead tubing pressure sustained for a period of 5 minutes or more. The [BC-S18 Monthly Injection/Disposal Statement](#) can be found on the Commission website.

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.

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

Production Testing

Prior to an injectivity test or disposal operation, the intended disposal zone must be production tested for any hydrocarbon potential. The well must be swabbed down to 80% of perforated depth to ensure no potential hydrocarbon reserves and obtain an uncontaminated formation fluid sample, with results included in the application.

Wellbore Integrity and 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 injection or disposal zone. Permit holders may reference ERCB Directive 51 for logging guidelines. 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.

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. Often a temperature log is the method used to confirm hydraulic isolation but other methods may be proposed by the operator. Instructions for conducting a temperature log can be found in the AER Directive 51 Appendix 2, and the Hydraulic Isolation Logging section below.
- Wellbores containing uphole zones with cement squeeze abandonment may not be suitable for disposal service. Experience has shown that cement squeeze abandonments can be prone to isolation failure. 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.

For wells greater than 10 years in age, the disposal well application requires a full length casing inspection and cement evaluation log. 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 may be acceptable up to packer depth 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 is required at time intervals specified in the approval Order, and submitted to the Commission, to confirm the well remains suitable for continued service use. The primary purpose of further logging is to determine the casing condition above the injection zone, especially over the first 600 meters 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 uphole 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.

Conducting a full length casing inspection log typically requires removal of the tubing and production packer. In wells that 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 order to avoid creating more risk but still add value, the Commission will generally accept casing inspection logs run down to the packer depth. This may consist of releasing packer from tubing using an on-off tool and pulling tubing. In order to avoid pulling tubing altogether, the Commission is also accepting through-tubing casing inspection logging.

Packer removal may still be required if there are downhole porous zones not blocked off by packer or bridge plug or if the production packer is not set close enough to the disposal zone (ie there are porous intervals that would not be logged). Section 16(2)(a) of the Drilling and Production Regulation states:

A well permit holder must: set a production packer in the well as near as is practical above the injection interval.

For the most part, the expectation is that operators will follow the above regulation, which is expected to be within 15m or the top of the completed interval. Therefore a casing inspection log down to the depth of the packer should provide reasonable assurance that there is good casing condition down to the zone of interest. Additionally, it is the expectation of the Commission that wells with porous zones below the zone of interest have those zones blocked off, either by a packer or a bridge plug. Again, in these situations there should be a packer set as close as practicable below the injection interval. A note on 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 perfs, 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.

Hydraulic Isolation Logging

Periodic hydraulic isolation logging is also required as a condition of new disposal well approvals. This 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 will consist of a time-lapse temperature log measured at 30, 60, 90, and 120 minutes after the injection of a cold fluid into the well, and compared to a baseline. (Refer to [AER Directive 51 Logging Guidelines](#) for guidance).

If available, the best baseline to compare to is the baseline temperature log run prior to any injection into the well.

Typical procedure for testing:

- Shut in well for a period of time to allow reservoir stabilization of the disposal zone. (refer to AER Directive 51 for suggested shut-in times based on prior length of continuous injection). Recommended for this test to coincide with the annual reservoir pressure test, both of which require shut-in time.
- Run baseline temperature log. If the shut-in time was long enough, this log should appear to return to geothermal over the length of the wellbore, except over the injection zone which is cooled by the long-term injection.
- Inject fluid at a temperature that differs from geothermal by *at least* 5.5°C at the injection zone. The greater the temperature differential, the easier to see any anomalies on the log. In order to achieve this, this test might best be done during the winter when ambient temperature will cool the injected water. The fluid should be injected at approximately the same rate as ordinary operations, and with a volume sufficient to provide the relevant cooling (or heating).
- Log the timed passes at 30, 60, 90, and 120 minutes after injection. Based on a tool run time of ~10m/min, there may be a limit to the distance that can be logged. For this reason, the log should be run from approximately 200m above the injection zone to just below the base of perfs.

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 300m 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) may be preferred. If the temperature log is unclear or a leak is suspected, a radioactive tracer survey may be requested to better pinpoint the area.

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)

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 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.

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 the eSubmission Portal. 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 submitted to welldatamail@bcogc.ca. As noted in Production Testing above, a pre-test attempt to obtain hydrocarbon inflow must be performed.

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 increase connectivity. Once a well has been granted disposal approval by the Commission, the approval Order includes a condition prohibiting future hydraulic fracture stimulations. 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.

Permit holders are cautioned to design and limit fracture stimulations to remain contained within the disposal formation. If planning a fracture stimulation post disposal initiation, submit to the reservoir engineering department a fracture plan that includes the intended size and maximum treating pressures, together with results from fracture simulation software. Where it appears there is significant potential that the induced fractures, and thus pathways for disposal fluid migration, has occurred out of zone, the Commission may require additional tests and data to confirm isolation and integrity of the bounding formations.

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 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 is sometimes impossible with a highly deviated well. If the zone is hydraulically fracture stimulated, care must be taken to ensure that the stimulation remains in-zone.

Seismicity

Some disposal wells have been linked to induced seismic events. 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 ceasing disposal injection. Array of seismometers may also be ordered by the Commission to closely monitor event location 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.

Packer Isolation Testing

Before disposal operations begin, a pressure integrity test is required. This is standard pressure testing requirement when any completion or workover is conducted on a well. The casing or casing/tubing annulus must be pressure tested to a minimum pressure of 7,000 kPa for 10 minutes prior to the commencement of injection or

disposal operations. (See the [Oil and Gas Activity Operations Manual](#) requirement for activating suspended wells and for suspending wells). A pressure test is considered successful if the pressure does not vary by more than three per cent during the test period. This pressure test is required before disposal begins but is not the same requirement as the annual packer isolation test.

Annual packer isolation tests must be conducted in accordance with Appendix D of this document. 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.

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 BC OGC 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 zone 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 as 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 BC OGC Hydrogeologist uses the documented information to develop well-specific recommendations for groundwater monitoring to be 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 BC OGC 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 BC OGC 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.

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).

Facilities

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

Source of Disposal Fluid

The Commission does not specify or restrict the **source** formation 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.

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 causing metal pitting or scaling. High pH values of the disposal water will inhibit the H₂S affect. 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.

Notification and Reporting

The form BC-11 Notice of Commencement or Suspension of Operations must be submitted to the Ministry of Finance by the 20th day of the month following the date of initial disposal, informing of date of initial operation.

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

For each month during which water is disposed into the well, a form BC-S18 Monthly Injection/Disposal Statement must be filed, reporting total injection hours, volume and maximum wellhead tubing injection pressure. The BC-S18 is due by the 25th day of the month following injection. Should the well operate seasonally or be shut-in temporarily, continue to submit monthly S-18 Injection/Disposal reports, with values of zero "0" for volume, pressure and hours. This verifies that well is temporarily inactive, avoiding flagging for potential reporting noncompliance. Both the [form](#) and [instructions](#) are available on the Commission website.

If the disposal well is not anticipated to be utilized for a period of 1 year or more, please submit a form BC-11 changing status from "Active" to "Suspended". Once changed to Suspended, cease submission of S-18 reports

A change in operations, such as at start-up or a rate change, can result in momentary pressure spikes. The BC-S18 reported wellhead pressure is the maximum pressure, sustained for a period of a minimum of 5 minutes continuous duration, experienced during the reported month.

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, the pressure limited to a value specified in the disposal approval Order.

A final reservoir pressure is required prior to abandonment, to confirm the final formation pressure resulting from the disposal operations. This pressure will provide a valuable data point to be used for any future work in the area (such as drilling or recompletions) or on the well.

Disposal intervals in a disposal well are normally subject to the requirements of a Level-A abandonment program, as specified in AER Directive 20 "Well Abandonment".

Approval Termination

Approvals for wells that have been surface abandoned are automatically terminated. 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 termination.

Dual Water Source and Water Disposal Well

Several wells, notably completed in the Debolt formation in the Horn River Basin, utilize the same interval as both a water source and for disposal. Additional formations are being investigated, in other areas, 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 submission of BC-11.

During cycles of disposal or production the appropriate forms (BC11, BC-S1 or BC-S18) must be filed.

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.

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, are based on comparative reservoir qualities of thickness, permeability and porosity, and the results of any well testing, such as injectivity tests or spinner surveys.

Typically 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

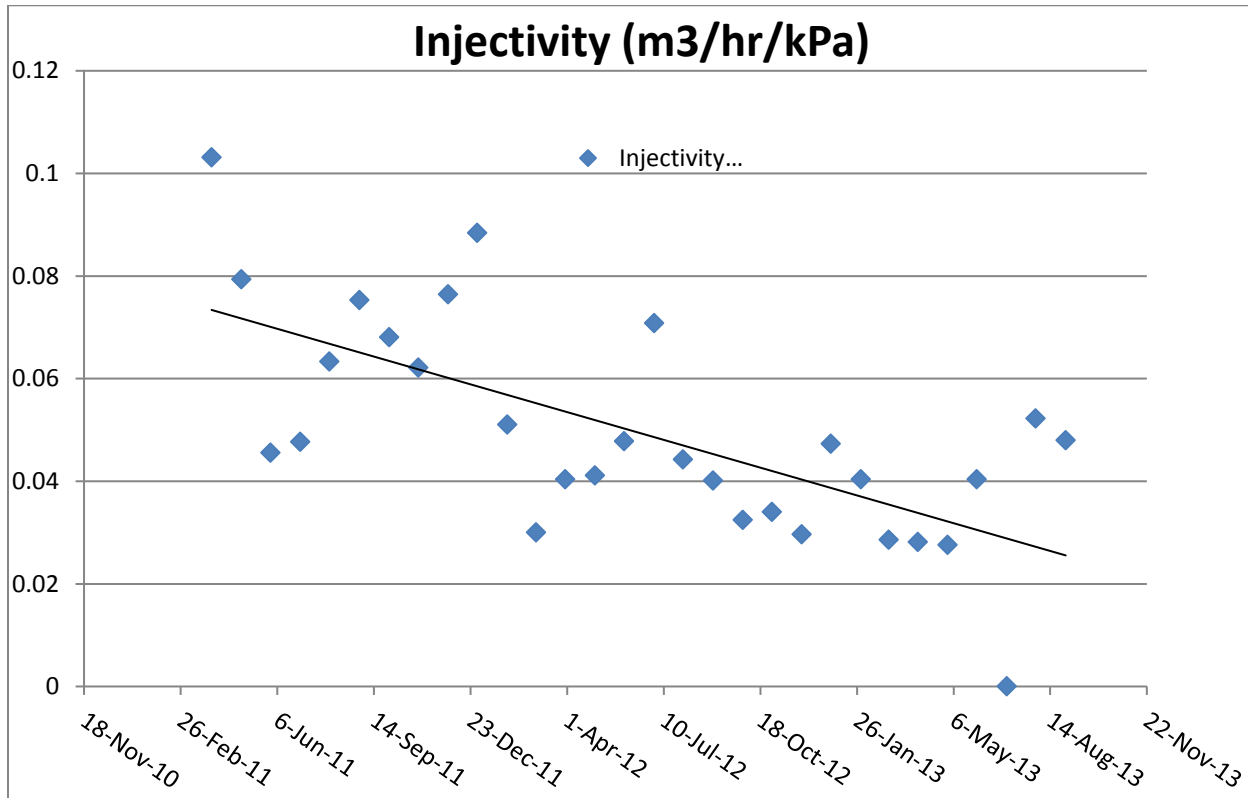
be based on the most conservative numbers for fracture gradient and initial reservoir pressure, which come from the upper zone. If the formations are close together, the well may be approved for unsegregated disposal into both zones, with a packer set atop the upper zone. In this case the Commission may set a limit to the amount of time that the zones can remain open to each other during downtime, to prevent cross-flow. Typically this is a 3 month period. 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.

Performance Monitoring

Similar to performance monitoring of producing wells in order to forecast rate, ultimate cumulative volume and identify well performance issues that may require remediation, prudent operators are recommended to track 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.

Example 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 [OGC 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)

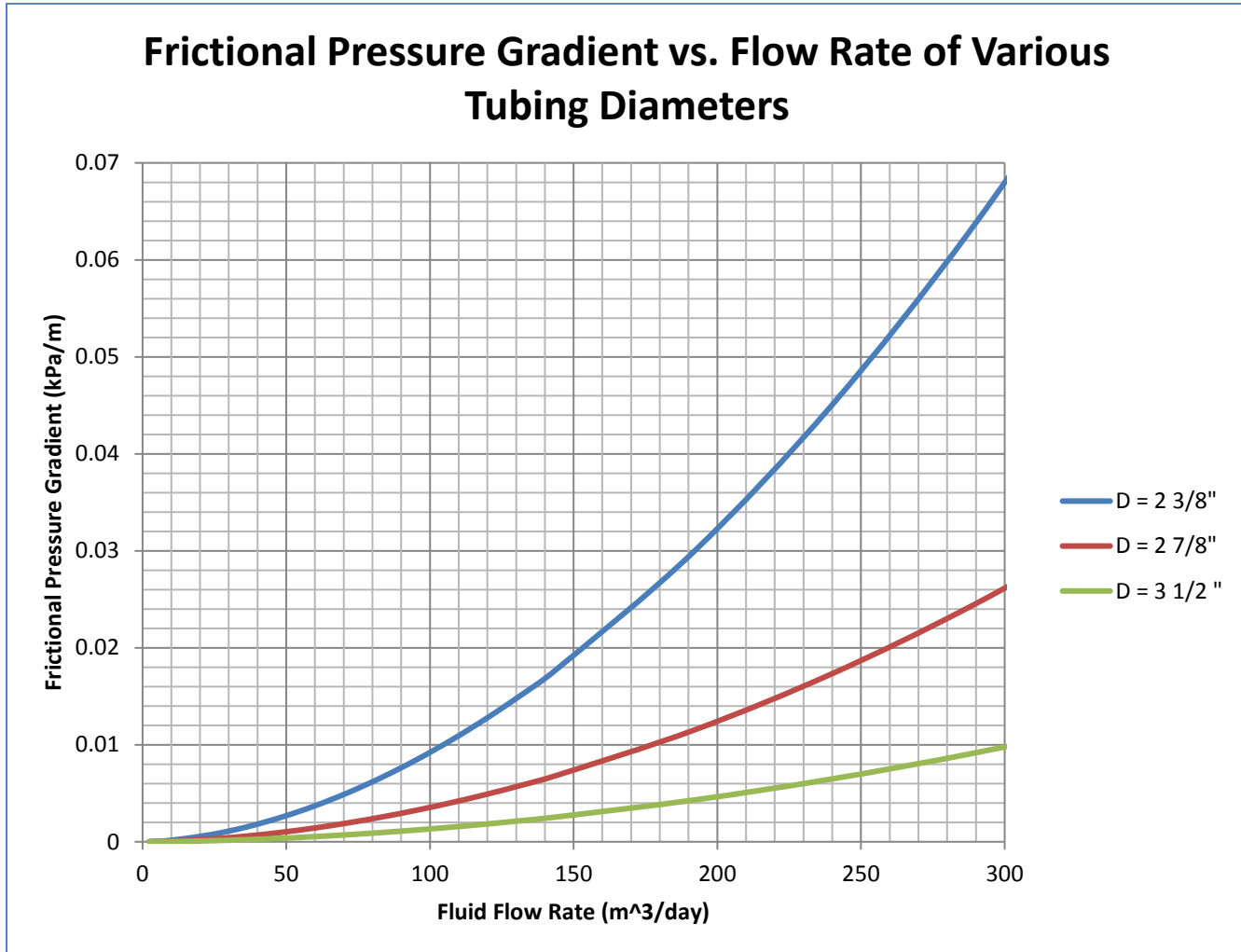
$$P_{\text{wellhead}} = [25 \text{ kPa/m} \times 1137.0 \text{ m} \times 0.9] - (10.5 \text{ kPa/m} \times 1137.0 \text{ m}) + 200 \text{ kPa}$$

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

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

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: Packer Isolation Test Procedure

Maintain stable operations 12 hours prior to and throughout the test period. If the well was on injection, continue steady injection operations. If the well was shut-in, do not start operations during the test. Changing operating conditions just before or during a test may result in unstable casing pressure readings.

1. Upon arrival on site, record initial casing and tubing pressure.
2. If the casing pressure is not 0 kPa, bleed down casing to 0 kPa. Record bleed-off volume.
3. Pressure test casing annulus to 1,400 kPa and allow pressure to stabilize. Record annular fill volume.
4. After stabilization, record the casing pressure change over a 10 minute period.
5. Bleed off casing pressure to 0 kPa and record bleed-off volume.
6. Record the casing shut-in pressure for 24 hours.

In order to pass the pressure test, the pressure change must be less than 3% of stabilized test pressure during Step 4, AND the casing pressure increase after 24 hours of shut-in must be less than 42 kPa.

The packer isolation test report submitted to the Commission should include the graphs of casing pressure vs. time obtained during Step 4 and Step 6.

Please submit a PDF file of the report to welldatamail@bcogc.ca with the naming convention WANUM_PIT_YYYYMMDD_OPTIONAL (example: 11122_PIT_2015JUN05_PASS). YYYYMMDD is the date the test was performed. The optional portion of the naming convention may be any alphanumeric text up to 40 characters in length. eSubmission of packer isolation tests reports is under development and will be available soon.

Appendix E: 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	S1 and Framework Requirements	Oil and Gas Activity Application Manual Summary Information for Water Source Wells document.
Water Injection	Y	Y	N	Y	none	S18	Pressure Maintenance or Improved Recovery
Water Disposal	Y	Y	N	Y	none	S18	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.

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](#).