BRITISH COLUMBIA ENERGY REGULATOR

Carbon Dioxide Subsurface Storage Summary Document

VERSION 1.0: April 2025

About the Regulator

The BC Energy Regulator (Regulator) is the single-window regulatory agency with responsibilities for regulating energy resource activities in British Columbia, including exploration, development, pipeline transportation and reclamation.

The Regulator'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, Mission and Values

Vision

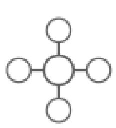
A resilient energy future where B.C.'s energy resource activities are safe, environmentally leading and socially responsible.

Mission

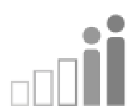
We regulate the life cycle of energy resource activities in B.C., from site planning to restoration, ensuring activities are undertaken in a manner that:

Protects public safety and the environment

Supports reconciliation with Indigenous peoples and the transition to low-carbon energy



Conserves energy resources



Fosters a sound economy and social well-being

Values

Respect is our commitment to listen, accept and value diverse perspectives.

Integrity is our commitment to the principles of fairness, trust and accountability.

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.

Responsiveness is our commitment to listening and timely and meaningful action.

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Carbon Dioxide Subsurface Storage Summary Document

This document is intended to support both the application and operation of a project for the subsurface storage of carbon dioxide. The Carbon Dioxide Subsurface Storage Application Guide is located at Carbon-Dioxide-Storage-Application-Guideline.pdf.

This document contains information to include an audience which may not have significant oil and gas operations experience. This is in recognition that oil and gas operations involve similar principles, technology, and considerations as operations for CCS. Some information is partially repeated in more than one section of this document, to clarify considerations and allow quick reference to individual sections by the user. The document is not intended to take the place of the applicable legislation. The user is encouraged to read the full text of legislation and each applicable regulation, and to seek direction from BC Energy Regulator (BCER) staff, if necessary, for clarification.

Please Note:

All submissions made to the Regulator in support of an application or a regulatory requirement that include work relating to the practice of professional engineering or professional geoscience are expected to accord with the Professional Governance Act, [SBC 2018], c. 47 and the Bylaws of Engineers and Geoscientists British Columbia (EGBC). This includes any requirements relating to authentication of documents.

Additional Guidance

As with all Regulator 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 Regulator staff for clarification.

The Regulator publishes both application and operations manuals and guides. The application manual provides guidance to applicants in preparing and applying for permits and the regulatory requirements in the planning and application stages. The operation manual details the reporting, compliance and regulatory obligations of the permit holder. Regulator manuals focus on requirements and processes associated with the Regulator's legislative authorities. 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. For example, Federal Fisheries Act, Transportation Act, Highway Act, Workers Compensation Act and Wildlife Act.

Throughout the document 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 Regulator website.
- Documentation and guidelines on the Regulator website.
- Frequently asked questions on the Regulator website.
- Advisories, bulletins, reports and directives on the Regulator website.
- Regulations and Acts listed on the Regulator website.

In addition to those listed above, this document references specific documentation available on the Regulator's website, including:

- Acid Gas Disposal Wells Summary Doc
- Acid Gas Report Requirements Doc
- The Water Service Wells Summary document includes information on calculation of the Maximum Wellhead Injection Pressure, the well testing process prior to application and Packer Isolation Testing.
- Geoscience BC published a Northeast BC Geological Carbon Capture and Storage Atlas, supported with pool mapping, reserves and other data from the BCER.
- The Plans CO2 Reduction Partnership, of which the BCER is a member, published the PCOR Partnership Atlas CCS explanation information and regional geologic suitability mapping.
- An easy-to-read CCS background document is published by the International Association of Oil and Gas Producers, Report 652 "Recommended practices for measurement, monitoring, and verification plans associated with geologic storage of carbon dioxide".
- Quest CCS facility: Halite damage and injectivity remediation in CO2 injection wells - ScienceDirect
- Numerous publications and papers are available from agencies and academia to assist in understanding CCS and project considerations.

For any questions or discussion regarding a potential CCS Project, please contact Reservoir@bc-er.ca. Staff are available for meetings to discuss proposals.

The BCER website contains an online library of reservoir project approvals, which may be searched by type, field, formation, or applicant company.
Approvals | BC Energy Regulator (BCER) (bc-er.ca)

Effective CCS operation involves numerous considerations for fluid quality, operational control (such as on-off vs steady injection), well design and the reservoir, such as fines migration, effect of carbonic acidization of connate water, halite precipitation pore blockage, etc. While the BCER is focused on public safety and environmental protection, our "resource conservation" mandate remains of high importance. Effective use of existing wells and reservoirs for CCS supports climate mitigation, energy activities, and impacts surface disturbance if replacement wells are required.

The term “the greater good” is used without specific definition, as a variety of factors would be considered and weighed. New land disturbance vs utilizing existing developed locations, pipeline safety risks, size of remaining reserves vs CO_2 capture opportunity, etc. It is the responsibility of the proponent to detail the particulars of their case.

For guidance on government policy and regulatory developments related to CCS as well as information on existing, and anticipated economic incentives, aimed at promoting CCS deployment in the province, please contact the Ministry of Energy, Mines and Low Carbon Innovation.

Manual Revisions

The Regulator is committed to the continuous improvement of its documentation. Revisions to the documentation are highlighted in this section and are posted to the Energy Professionals section of the Regulator's website. Stakeholders are invited to provide input or feedback on Regulator documentation to Systems@bc-er.ca.

Version Number	Posted Date	Effective Date	Chapter Section	Summary of Revision(s)
1.0	April XX, 2025	XX	-	This is a new document. Users are encouraged to review in full.

Background

Carbon capture and storage (CCS) in subsurface reservoirs contained in geologic formations is an internationally recognized greenhouse gas emissions mitigation strategy. CCS projects are operating in Canada and around the world, as both CO_2 sequestration projects and as CO_2 injection enhanced oil recovery operations. Injection of CO_2 into reservoirs is a well understood science and mature technology.

Under the Energy Resources Activities Act (ERAA), the BC Energy Regulator regulates CCS projects for the subsurface storage of CO_2, regardless of the source of the CO_2. A CCS project may consist of anywhere from a single injection well to multiple injection and observation wells, appropriate for the specific circumstance. This guide addresses the use of a well(s), once drilled and tested, and the storage reservoir, for CCS service. Use of the term "fluid" applies to both a gas or liquid, unless specified.

Subsurface storage of carbon dioxide is approved as a Section 75 Special Project under ERAA, with conditions for operation, measurement, monitoring, testing and reporting appropriate to the project. The Regulator employs geoscience and engineering professionals in the review and approval determination process.

Section 80(3) of the Drilling and Production Regulation specifies -
"A well permit holder of a well that is part of a special project for carbon dioxide storage designated under section 75 of the Act must construct and operate the well in accordance with CSA Standard Z741".
Canadian Standards Association Z741-12 "Geological Storage of Carbon Dioxide" contains a wide range of topics to be addressed. While a standard outlines minimum requirements, a proponent may propose a design that goes above and beyond the specifications. The standard is available for purchase from CSA Standards -- Standards Development | CSA Group.

Subsurface storage of captured CO_2 requires the use of an injection well(s) and a suitable storage reservoir, and potentially separate monitoring well(s) drilled to the depth of the storage reservoir or formations above it. CCS requires tenure of the subsurface formation in which storage occurs, as well as potentially formation(s) used for monitoring above, depending on the activity. There are two potential forms of tenure, as discussed in a later section of this guideline.

For CO_2 source industrial activities that are not regulated by the BCER, for example CO_2 capture at a pulp mill that is destined for subsurface storage, the BCER regulates the CO_2 compressor and CO_2 pipeline and downstream activities. Separate permits, upon application, are granted for facilities, pipelines, and wells. Upstream of the compressor remains under the purview of other regulatory authorities, including WorkSafeBC.

The terms storage and sequestration are often used interchangeably. The term storage historically referred to the potential to withdraw a substance if desired in the future. Sequestration indicated no intent or ability (such as mineralization of the fluid) to withdraw at a future date. For the purpose of regulating CCS, storage implies sequestration.

CCS activities covered in this guideline are inclusive of all that pursue subsurface geological storage. This includes storage into underground formations, depleted oil and gas reservoirs, and basalt rock.

Primacy of Reservoir Storage Capacity

Storage reservoirs for CCS are limited to locations with suitable geology. Reservoir storage capacity is a limited resource.

Currently, the highest value use of suitable reservoirs is storage of natural gas (and potentially hydrogen). This storage provides a ready supply that can be recovered when needed. Natural reservoirs of the quality (high injectivity, productivity and recovery) and location required for natural gas storage use are rare in the province.

Some reservoirs may be suited for simultaneous activities, for example production of natural gas or oil, while also injecting a fluid for sequestration. Contact of the injection fluid with producing wells can be delayed, due to distance and geologic structure, allowing production to continue without the withdrawal of injected fluid. In some circumstances, it may be permissible to forgo a portion of the hydrocarbon remaining reserves in a pool to allow CCS to proceed, if that decision is in the greater interest of the Province.

The potential for competitive use of a reservoir for CCS, acid gas disposal, or produced water disposal, will be weighted to the overall benefits “for the greater good”. The proponents’ access to an alternative reservoir(s) may be considered in a situation of proposed competitive use.

For regulatory purposes, CO_2 enhanced oil recovery is not considered a CCS project. An application for CO_2 injection enhanced oil recovery may be applied for using the Guideline “Pressure Maintenance or Improved Recovery Project Application Guideline”.

Storage Fluid Composition

To be designated a CCS Project by the BCER, the project’s primary intent must be the reduction of carbon dioxide in the atmosphere. This may be either the interception of CO_2 prior to emission or capture of CO_2 from the atmosphere.

Gas treatment processes with a primary purpose other than CCS (i.e. raw gas sweetening removal of H_2S which, as a by-product, also captures CO_2) will continue to be considered acid gas disposal. CO_2 is expected to be the overwhelmingly dominant component in the CCS injection fluid. The injection of atmospheric nitrogen or nitrogen compounds is a wasteful use of CCS storage reservoir capacity and therefore must be removed either pre or post combustion.

The expected CO_2 purity of the injection stream is to be addressed in the application, and a minimum CO_2 percentage value for the injection stream is included as a condition of the approval, with a requirement for periodic gas sampling and analysis submissions to ensure compliance.

Canadian Standards Association Z741-12 “Geological Storage of Carbon Dioxide” provides the following definition:

> **Carbon dioxide (CO_2) stream** — a stream of carbon dioxide that has been captured from an emission source (e.g., a fossil fuel power plant) and meets applicable regulatory requirements for CO_2 storage.
>
> **Note:** It may include any incidental associated substances derived from the source materials or the capture process and anysubstances added to the stream to enable or improve the injection process and/or trace substances added to assist in CO_2 migration detection.

Source of CO2

A CCS project for subsurface storage may source the CO_2 as a waste by-product from any industry, or from a direct air capture (DAC) facility.

Examples of industries noted as stationary point-source CO_2 emission sources, potentially suitable for CCS, include metals and hydrocarbon refining, pulp and paper, cement plants, and power generation.

Two oil and gas activity sources of CO_2 are:
1) formation CO_2 which is a by-product of raw natural gas, removed to meet natural gas sales specifications, and
2) flue gas CO_2 generated from the combustion of fuel for power and process heat at oil and gas facilities.

CCS & Acid Gas Disposal

Acid gas, consisting of H_2S and CO_2, is a waste fluid by-product of raw natural gas production, removed during processing. The first acid gas disposal well in the province commenced operation in 1996. A total of 19 acid gas disposal wells have been approved as of September 2024. Oversight of these wells has provided significant experience for the regulation of CCS.

Existing acid gas disposal wells and reservoirs may be suitable for blended injection, adding a CCS source. This may be the addition of a CCS injection well into the same reservoir in which acid gas disposal is occurring, or the addition of a CO_2 source to an existing acid gas disposal stream, utilizing the same injection well and increasing the percentage of CO_2 in the injection stream.

A blended source injection project requires a separate ERAA section 75 approval for portions of the activity, to ensure CCS receives any eligible recognition and credits. Separate metering of each source is required prior to injection.

Well Permit and Classification

When drilling a **new well for storage or observation** the standard Well Permit application form and requirements apply. Information on the Well Permit application process can be found in Oil and Gas Activity Application Manual on the Regulator's website.

To convert an **existing well to storage injection** service, an amendment to the existing Well Permit is required. The following steps are required. Submit:

1. A Notice of Operation to the Regulator prior to work on well http://www.bcogc.ca/node/5753/download
2. A Well Permit Amendment Oil and Gas Activity Application Manual to BCER permitting department Amend-a-Well-Permit-for-Special-Project-Purpose.pdf (bc-er.ca)
3. An application for carbon dioxide subsurface storage well service to the BCER Reservoir Engineering Department. Carbon-Dioxide-Storage-Application-Guideline.pdf (bc-er.ca) If approved, specific operation, testing, measurement, monitoring, and reporting requirements will be ordered as conditions of approval.
4. A facility permit amendment application to the BCER Facility Department, for the equipment changes at the associated facilities. For example, the gas processing plant where the carbon dioxide gas compression is located becomes the facility to be set up in the Petrinex system. Oil and Gas Activity Application Manual | BC Energy Regulator (BCER) (bc-er.ca)

To convert an **existing well to observation service**, an amendment to the existing Well Permit is required. The following steps are required. Submit:

1. A Notice of Operation to the Regulator prior to work on well http://www.bcogc.ca/node/5753/download
2. Submit a Well Permit Amendment Oil and Gas Activity Application Manual
3. An application for observation designation. The approval contains specific operation, testing, monitoring and reporting requirements observation-well-application-guideline-nov-release-2018.pdf (bc-er.ca)

Also, see the later section of this guideline titled “Observation & Monitoring Wells”. Note, observation wells are used for the purpose of collection data from a deep formation. Monitoring wells are shallow wells, typically for monitoring groundwater chemistry.

Well classification (Development, Exploratory Outpost, or Exploratory Wildcat), which determines the period of well data confidentiality, is independent of the purpose of a well and is assigned at time of well permit application review, based on distance of the well from a designated oil or gas pool. 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 will be used if a gas pool is nearest).
See the Drilling and Production Regulation section 2
DPR-266-2022-Early-Consolidation.pdf (bcogc.ca)

Wells drilled into depleted oil or gas pools are normally classified as Development. As a saline aquifer does not qualify as a “designated oil or gas pool”, it is possible for adjacent wells into a saline aquifer to continue to qualify for a classification other than Development.

Well classification determines the period of well data confidentiality, ranging from 3 to 12 months following the well rig release date. A well may qualify for “special data well” designation (18-months confidentiality) based on data collected & submitted.
Confidential periods are administered under ERAA General Regulation section 17
Energy Resource Activities General Regulation (gov.bc.ca)

CCS projects are not eligible for an “Innovative Technology” (ERAA 75(1)(b)) Special Project, and the associated 3-year confidentiality. By definition, “innovative technology” only applies to production, also, CCS is generally considered to be an understood technology.

Public data reporting regarding CCS operation is considered of greater benefit than granting an extended period of proprietary data confidentiality. Availability of data promotes adoption of technology by others and information transparency for public acceptance of the activity. The Well Permit holder has the option to waive the well confidentiality period under section 17(7)(b) of the ERAA General Regulation. An applicant’s waiver of a period of confidential status for project wells can be stated, i) in the CCS project application, ii) at the time of Well Permit application, or, iii) any time thereafter by written notice to the BCER.

“Well Status” is used by the Regulator to identify the current state of the well, through the data fields of Fluid Type, Operation and Mode. The status of a well utilized for the injection of carbon dioxide is identified by a Fluid type “CO2” and an Operation type “STOR”. The Mode is determined by the current well activity, “ACT” (active), “SUSP” (suspended), etc.

Note that wells drilled for the purpose of CCS data gathering, including use of a “diamond drilling” coring rig normally utilized in the mining industry, are regulated by the BCER when used for this purpose and a Well Permit is required (exceptions are coring regulated under the Mines Act). Unless otherwise approved, core must be placed in suitable containers and submitted to the BCER core warehouse located at our Fort St John office address. Requirements are outlined in sections 29 and 30 of the Drilling and Production Regulation. Core removal for examination is subject to section 31 of the same regulation.

Well Spacing and Target Area

Injection and observation wells are not subject to the well spacing and target area restrictions which apply to oil and gas production wells. Flexibility in well placement enables use of locations with consideration for surface disturbance and reservoir geometry. The CCS Project area includes the completed section of project wells. A condition of approval requires the subsurface location of the completed portion of project wells to be no closer than 100 metres to the project boundary. Additional information is contained in the section “Project Area Considerations”.

Commingled Reservoir Storage Potential

Stacked reservoirs, in different formations and without natural vertical communication, may provide an attractive cumulative CCS opportunity. A proponent may examine sequential injection and decommissioning of individual reservoirs encountered in a well, or the simultaneous (commingled) injection into two or more reservoirs via the same well. A potential drawback to commingled injection in the same well is that the approved maximum wellhead injection pressure and the maximum reservoir storage pressure are based on the shallowest reservoir. Alternatively, the proponent may inject simultaneously into different reservoirs, each completed in different wells, using common facilities and individual well metering. A dual-completion / dual string well is not advised, as these offer limited injection tubing size (injection must be via tubing) and are complex for packer isolation testing.

In these scenarios, either a single or multiple CCS Project approvals may be required, depending on circumstances, and should be discussed with the Regulator early in the design.

Reservoir Suitability

A CCS storage reservoir must be capable of sequestering CO_2 for geologic time, many thousands of years. Storage integrity is composed of two considerations; i) ability to geologically trap fluid in the storage reservoir, and ii) well integrity (including historic existing wells, new CCS project wells, and wells that intersect the storage reservoir in the future).

i) Reservoir Containment

In sedimentary formations, a suitable storage reservoir may be either a depleted oil or gas pool, or a saline water saturated formation. These reservoirs have demonstrated conditions to trap fluids for millions of years.

An analogy to CCS storage has been produced water and acid gas disposal projects, that have successfully stored large volumes of fluid in similar formations to those prospective for CCS. Other potentially suitable CCS storage reservoirs include coalbed seams or non-sedimentary formations, such as basalt, where containment may be achieved through the mineralization of the injected CO_2.

The proponent is responsible for demonstrating how the CCS project will be capable of sequestering CO_2. Containment risks that must be addressed include potential migration to the atmosphere, to shallow useable water aquifers, or other subsurface formations. Potential migration paths to be considered include:

1. existing wells (operating, suspended, and decommissioned)
2. future wells
3. natural conduits, such as faults

Further information on considerations for reservoir types is contained in the section "Project Area Considerations" in this document.

ii) Wells

Wellbores penetrating the storage formation present a potential pathway for the vertical migration of fluids. Well drilling, casing and cementing procedures are designed to provide a secure system to contain fluids within their host formations.

A detailed review of all existing wells, which may be contacted by the storage pressure plume, is required. This review must examine any issues noted during drilling and over the life of the well, to highlight potential integrity concerns. This list includes both wells completed and not completed in the formation of interest, regardless of their current status. A table format provides a summary of key information – age, depth, casing, cement, use, present status, etc. Of particular interest is the cement bond log (CBL) and any casing integrity logs, if performed. Both log types require interpretation by experts, usually a report accompanying the log submission. Where a cement bond log is not available, the original drilling report may be examined for note of circulated cement returns to surface – though this is not a clear indication of well integrity. Where no cementing data is available, a CBL may be required. The results of surface casing vent flow tests for the above list of wells must be included in the application, as well as any noted gas migration.

BCER Records provides a publicly available file for each oil and gas well in the province, a primary information source.

Decommissioned (abandoned) wells must be reviewed to ensure the subsurface decommissioning work program has left the well in a state capable of maintaining the isolation of fluids in contact. For abandoned wells in the area of CCS subsurface plume, a table must list the abandonment details. Where it is identified that a more rigorous abandonment is required for an offsetting well, the CCS proponent is responsible for working with the off-setting well liability owner to have such work completed.

The CCS application must also address considerations for the drilling of future wells over the storage life of the reservoir, wells either i) completed in the same reservoir, ii) drilled through the storage reservoir with a deeper formation as the objective, or iii) completed in proximity with potential for communication due to hydraulic fracture stimulation. Such wells must be drilled, constructed, and maintained to provide ongoing storage reservoir integrity. The CCS operator must have a plan to remain vigilant of any area activities and contact permit holders to coordinate information and potential operations, ensuring the reservoir storage is protected. The BCER well permitting system includes a caveat in well permits issued within a 3 km radius of an approved CCS project area, providing warning regarding the non-native fluids and pressure that may be encountered; however, this should not be relied upon as a safeguard for awareness.

Application Process

The Carbon Dioxide Subsurface Storage Application Guide, instructions for a submission to the BCER, is located in the Carbon-Dioxide-Storage-Application-Guideline.

Prior to the issuance of a CCS Project approval, the initial injection well(s) must be drilled, completed, and tested to verify both the well and reservoir are suitable for CCS service.

The guide outlines the expected information to be included in the application. Where certain data is not available, that deficiency should be stated with the reason(s) why and offering data to achieve the same informational goal as the requirement. Relevant information in addition to that stated in the guide may be included where it may be pertinent to rendering a decision on the suitability of the project.

Where an application is prepared by a consulting company on behalf of a proponent who is the permit holder of project wells, a submittal cover letter verifies that the work is on behalf of the proponent and provides proponent contact information.

Upon receipt of application, a notice of application for operation of a CCS Project is posted by the BCER to the BCER's website for a 21-day period to allow any concerns to be filed with both the BCER and the applicant. This posting is primarily targeted to well permit and subsurface tenure owners, as the BCER pre-consultation and consultation processes address surface stakeholders. 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 located in the Reservoir Engineering Projects Notification and Objections Process.

Consent letters from offsetting rights holders are not required to be submitted with the application, unless the proposed CCS operation will clearly influence those rights, such as injection into a pool with completed wells of different ownership. It is a recommended practice to consult with potentially affected offsetting rights owners prior to application, to preclude the later filing of technical objections during the application notice period, which can significantly delay the review process.

During the posting period of a CCS application, a technical objection by an offsetting tenure owner or well permit holder may be considered, examples being:

i) potential hydrocarbon recovery from the pool would be jeopardized, with evidence of the remaining reserves and plans for production.
ii) an existing natural gas storage operation would be impacted.

An objection will be evaluated by the Regulator based on the greater good.

Application review by the BCER may be iterative, with requests for elaboration on points and for additional data, rather than outright rejection of a deficient application. However, where substantive changes are necessary, a re-submission of the application may be required to provide a single cohesive document.

Fundamentally, the application and approval process must ensure the integrity for containment of both the well(s) and the storage reservoir. A Section 75 order contains specific conditions for initial inspection, ongoing operation, monitoring, measurement, testing, and reporting.

Consultation

The BCER consultation process provides opportunity for a proponent to engage with stakeholders, be aware of concerns, and implement mitigations. Early consultation is recommended as an opportunity to provide factual information.

When engaging with First Nations, communities and stakeholders, the project should be presented as a whole, including all expected surface disturbances both during construction and operation.

For further information refer to the Requirements for Consultation and Notification Regulation (gov.bc.ca) and the Guidance for Pre-engaging with Indigenous Nations.

Risk Assessment

The proponent for a CCS project is required to conduct a thorough risk assessment to identify and mitigate any potential public or environmental harms.

The application must identify the risk assessment process utilized and highlight risks identified and the steps in addressing each.

The application sections on well integrity review, safety valves, reservoir modelling, etc. which constitute the application address specific risks in detail. These items will be listed in the project risk assessment.

CCS Project Types and Project Area Considerations

A CCS project approval includes a defined project area and formation. The project area is the contiguous gas spacing areas of **subsurface** rights, formation pore space required to operate carbon capture injection and sequestration. The subsurface CO_2 fluid plume may migrate across the formation from the time of operation to time of eventual stabilization; **all** of these lands are to be included.

The minimum project approval area, regardless of the storage formation being a saline aquifer or a depleted hydrocarbon pool, is 1 gas spacing area (1 section in the Dominion Land Survey or 4 units in the National Topographic System) according to section 8 of the Petroleum and Natural Gas Storage Reservoir Regulation. The 4 units which compose an NTS gas spacing area are pre-determined by the Petroleum and Natural Gas Grid.

With directional/horizontal drilling, it is possible for a well surface location to be outside of the subsurface impacted area. Similarly, observation (monitoring) wells referenced as part of the CCS Project may be located outside of the storage plume area. Generally, the project area will be broad enough to include all associated well surface locations, so they may be subject to project approval requirements. Wells integral to operation of the project are listed in the project approval with specific conditions as required. Observation wells may be subject to separate approvals, for administrative ease of amendment if required. Due to the potential size of the monitoring area, separate CCS projects may have some overlap in the project areas.

Pre-existing subsurface tenure may unreasonably prevent a CCS project from proceeding. A Storage Reservoir Licence is significantly different from normal tenure rights. A Storage Reservoir Licence may include an existing PNG lease area and formation held by the same or different interest holders. This non-exclusive right to a reservoir for CCS operation and storage impacts the project area determination. The conditions of a CCS project approval may address appropriate equitable reservoir use in competitive use situations, however the principle of “rule of capture” of pore space applies. The general principle is that the first person to “capture” the resource uses it.

Use of a reservoir for CCS requires storage tenure ownership of the formation in the form of either Petroleum and Natural Gas Lease or Storage Reservoir Licence.

Subsurface tenure, for CCS CO_2 sourced from oil and gas activity, may be either a Petroleum and Natural Gas Lease, or a Storage Licence. For CCS CO_2 that does not originate from the oil and gas industry, a Storage Reservoir Licence is required. For legislative specifics regarding Underground Storage, see Part 14, sections 125.3 to 133 of The Petroleum and Natural Gas Act. Information on tenure requirements is available from the Ministry of Energy, Mines and Low Carbon Initiatives at this link CCS tenure guidance document. Contact email address is PNGTitles@gov.bc.ca.

Where the proponent is not a registered tenure owner of parts or all of the CCS project area, a letter of consent from the registered tenure owner(s) is required for lands to be included in the reservoir project.

The following sections address considerations for different reservoir scenarios.

Saline Aquifer (CO_2 in liquid or dense phase)

This section deals with a water saturated reservoir at conditions of pressure and temperature that will sustain CO_2 in a liquid or dense phase at the time of initial injection through to reservoir stabilization. Liquid or dense phase CO_2 is injected.

Deep saline 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.

Aquifers targeted for disposal are generally regional in area. Some have shown a vast capacity for the disposal of produced water; however others have demonstrated characteristics of compartmentalization by geologic barriers of low porosity and permeability or faulting.

Because liquid and dense phase CO_2 has a lower fluid density than saline water, gravity segregation buoyancy is a factor in the migration pathway of the majority of the CO_2. A small percentage of injected CO_2 goes into solution in saline water under reservoir conditions.

The size of the project area is the gas spacing areas that 1) are anticipated to be contacted by the CO_2 plume at the conclusion of CO_2 injection, and, 2) the spacing areas at the time of reservoir stabilization, as shown by proponent reservoir modelling. Due to the buoyancy of dense phase CO_2, fluid injected into a structural down-dip location can be expected to migrate to the apex of the structural trap, baring the existence of baffles and solubility and mineralization effects. The reservoir model should incorporate the heterogeneity of the reservoir, as this will impact dispersion of the reservoir plume.

The project area may correspond to the area of the Storage Licence issued by the Ministry of Energy, Mines and Low Carbon Innovation (EMLI), but is not required to equate to, as additional information or interpretation may occur, especially from drilling results, following issue of the Licence, that indicates a small area will be impacted. If the additional data shows the plume will extend beyond the Storage Licence boundary, the licence holder must request an amendment to the Licence to include that area.

As noted, the minimum project approval area is one gas spacing area. A saline aquifer may be subject to offsetting CCS, acid gas, or produced water disposal or water source operation. To protect the reservoir space required for the anticipated CCS project life, the applicant may acquire control of that tenure.

Partially Depleted Pool (CO_2 in liquid or dense phase)

This section deals with a hydrocarbon pool (oil or gas) at or above the conditions of temperature and pressure that will maintain CO_2 in a liquid or dense phase at the time of initial injection through to reservoir stabilization. Liquid or dense phase CO_2 is injected. See Appendix B for properties of CO_2.

In some cases, the BCER will allow a CCS project to proceed which may result in the early termination of hydrocarbon production from the pool due to contact with injected CO_2 at producing wells prior to reaching their hydrocarbon rate economic limit. Or, the wells may be expected to reach that economic rate prior to plume contact. The BCER considers the “greater good” of recovery loss vs the benefit of CCS. There is not an established threshold volume or value of remaining reserves vs CCS injection rate/volume for making a determination, a case must be made by the applicant, demonstrating why other suitable CCS reservoirs are not considered for alternate use in the proximal area and the benefit of the project.

Partially depleted hydrocarbon pools have demonstrated the ability to contain a fluid at discovery pressure and temperature. Partially depleted pools contain a known reservoir storage capacity, based on the cumulative production volume of fluids, converted to their volume under reservoir conditions. This voidage volume can be used to approximate ultimate fill-up capacity, which should coincide with the reservoir reaching its initial pressure. Periodic reservoir pressure measurements, a condition of CCS operation, will confirm this prediction.

The size of the project area is the gas spacing areas that 1) are anticipated to be contacted by the CO_2 plume at the conclusion CCS injection and, 2) the spacing areas at the time of reservoir stabilization, as shown by proponent reservoir modelling.

Spacing areas included in the project area are expected to include a portion of the pool as defined by the net pay map published by the BCER. Net pay contour maps are available at https://www.bc-er.ca/data-reports/data-centre/p2/. Consideration can be made for additional areas outside the zero-edge gas/water or oil/water contact where shown by modeling that eventual dense phase CO_2 will displace downdip water, or where injection will occur in the pool water leg.

The project area may correspond to the area of the Storage Licence issued by EMLI, however additional information and interpretation may occur, especially from drilling results, following issue of the Licence.

The proponent is not required to hold ownership, or consent from owners, of tenure for the entire pool, only the portion effected by CCS. Other tenure and well permit holders have opportunity to raise technical objection to a CCS project application and should be contacted to plan to mitigate potential concerns.

Depleted or Partially Depleted Pool (CO_2 in gas phase)

This section deals with a pool at conditions of pressure and temperature that the CO_2 will be in gas phase in the pool at the time of initial injection. Injected compressed CO_2 in a liquid state will alter to gas state in the wellbore or reservoir. Of course, a much smaller amount CO_2 can be stored in a gas state than can be stored in a liquid or dense phase state in the same reservoir pore space, should conditions allow.

A key initial consideration is that CO_2 in a gas phase will rapidly disperse in the reservoir. The pool may be 1) fully depleted with no active production wells, or 2) partially depleted with remaining economic reserves.

In some cases, the BCER will allow a CCS project to proceed which may result in the early termination of hydrocarbon production from the pool due to contact with injected CO_2 at producing wells prior to reaching their hydrocarbon rate economic limit. The BCER considers the "greater good" of recovery loss vs the benefit of CCS. There is not an established threshold volume or value of remaining reserves vs CCS injection rate/volume for making a determination, a case must be made by the applicant, demonstrating why other suitable CCS reservoirs are not considered for alternate use in the proximal area and the benefit of the project.

Depleted hydrocarbon pools have demonstrated the ability to contain a fluid at discovery pressure and temperature. Depleted pools contain a known reservoir storage capacity, based on the cumulative production volume of fluids, converted to their volume under reservoir conditions. This voidage volume can be used to approximate ultimate fill-up capacity, which should coincide with the reservoir reaching its initial pressure. Periodic reservoir pressure measurements, a condition of CCS operation, will confirm this prediction.

The increase in pool pressure due to injection may, or may not, eventually reach liquid or dense phase state. A corresponding change in phase of the CO_2 injected would be required in such a case. Understanding changes in

behaviour of CO_2 at the conditions of temperature and pressure of the pipeline, well, and reservoir are critical to an effective CCS project. Information in this regard is available at this link
(26) How CO2 phase behaviour can derail CCS projects | LinkedIn

A depleted oil or gas pool can vary in size from a single former producing well, to hundreds of wells. The CO_2 in gas phase can be expected to eventually be present in all areas of the pool and in contact with all well locations. The applicant is required to own, or have consent from the owner(s), of the tenure rights to the entire pool to receive a CCS Project approval order. This may be in the form of either PNG Lease, where the CO_2 originates from the oil and gas industry, or a Storage Reservoir Licence. A Storage Reservoir Licence may be issued for the same formation and area(s) as existing PNG Lease(s), to facilitate sequestration of CCS that does not originate from the oil and gas industry, and where the existing PNG Lease do not contain active producing wells.

The spacing areas requested for the project area should each include a portion of the pool as defined by the net pay map published by the BCER, available at https://www.bc-er.ca/data-reports/data-centre/p2/. Consideration can be made for additional areas outside the zero-edge, below the gas/water or oil/water contact if injection will occur in the pool water leg.

Other Reservoir and Project Types

CSS projects may inject CO_2 which is dissolved in water. Dissolved CO_2 content increases the density of water and forms carbonic acid. Carbonic acid is corrosive to steel and some cement and causes dissolution of limestone and dolomite. Injection requires consideration of these qualities.

Potential CCS storage reservoirs include coalbeds or non-sedimentary basalt and serpentinite formations. Other rock formations may yet be proven suitable for CCS. Some rock types may promote rapid mineralization of the CO_2 for secure sequestration.

CO_2 can preferentially displace coalbed methane. Production of this methane provides CCS capacity. Coalbeds contain natural seams (cleats) which are normally water saturated, also providing potential CO_2 storage capacity in solution.

Basalt formations (mafic rocks) can contain natural porosity and permeability. A CCS pilot project in Iceland has demonstrated capacity for CO_2 injection and storage. This technology is also known as in situ carbon mineralization (ISCM).

Non-sedimentary formations may be suitable for hydraulic fracture stimulation or other methods to enhance CCS capability. The requirements of ERAA and the Drilling and Production Regulation apply, for safety and environmental protection, regardless of the rock type being developed for a CCS project.

Surface sequestration, such as use on mine tailings (also known as ex-situ carbon mineralization, or surficial carbon mineralization), is not a CCS Project for the purpose of this guidance.

CCS Approval Requirements and Conditions

An approval to operate a CCS project is granted by the BCER as a Special Project Order under Section 75(1)(c.1) of the Energy Resources Activities Act. The order contains conditions that must be met for the approval to remain valid, as failure to comply is a rationale for cancellation. The Regulator utilizes site inspections, verification reports, and audits to ensure compliance with conditions.

The following sections provide specifics on individual conditions typically listed in an approval order, which include operating limits, testing, measurement, monitoring, and reporting.

Pressure Limits and Testing

There are two pressure limits in operating a CCS Project:

- Maximum wellhead injection pressure (MWHIP) – measured at or as close as possible to the wellhead, based on a resulting bottomhole pressure that is 90% or less of formation fracture pressure.
- Maximum reservoir storage pressure – the ultimate limit to average reservoir pressure due to CCS injection.
    - Saline Aquifer (CO_2 in liquid or dense phase) - typically calculated based on 120% of the virgin reservoir pressure, prior to any production or injection within the reservoir. Limit based on pressures observed in naturally over-pressured conventional reservoirs.
    - Partially Depleted Pool (CO_2 in liquid or dense phase) - typically 100% of the virgin reservoir pressure, prior to any production or injection within the reservoir.
    - Depleted Pool (CO_2 initially in gas phase) - typically 100% of the virgin reservoir pressure, prior to any production or injection within the reservoir.

Either value may be lower, depending on the individual circumstances considering the state of penetrating wells and the sealing formations, and in the case of saline aquifers the risk of induced seismicity. Further details are provided below.

a) Maximum wellhead injection pressure (MWHIP)

Injection pressure must not exceed the formation fracture pressure. The BCER 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 (minimum stress or closure pressure).

Each injection well in a CCS project is subject to an MWHIP based on the depth at the top of the perforation interval at the time of issuance of the Section 75 Special Project Order. If the perforation interval changes in one of the injection wells, the Order must be amended to change the perforation interval and a re-calculation will also be done of the maximum wellhead injection pressure value.

Studies (see appendix E) indicate that the formation closure pressure, measured at the injection interval, is a suitable limit for injection pressure for two reasons: (1) it provides a conservative safety factor as existing fractures cannot propagate to provide a conduit for fluids potentially out of the storage zone, and (2) it is determined from standardized calculation methods. Further study of the relationship between closure pressure and an Instantaneous Shut-in Pressure (ISIP) in various formations is on-going. Subsequent releases of this guideline will detail results as they become available.

Injection fluid density is used for a hydraulic wellbore gradient to calculate a conservative wellhead pressure value. The BCER typically utilizes a value of 8.0 kPa/m as the dense phase CO_2 fluid gradient for calculating the maximum wellhead injection pressure, however the applicant is expected to include the maximum expected density, at wellbore injection conditions, in the application.

Wellhead injection pressures can be reduced by reducing the CO_2 temperature in the wellbore. The result is an increased fluid density and increased wellbore hydrostatic head. This, in turn, reduces the operating pressures for the CO_2 pipeline and compressors, which lowers the systems' energy requirement. However, fluid temperature below 4°C are prohibited as there is an increased risk of groundwater freezing around the wellbore leading to casing collapse.

Continuous recording of injection stream pressure and temperature provide data for bottom hole pressure calculation if the fluid is single phase. Two-phase fluid introduces density and compressibility complications that require Equation of State calculations to determine hydrostatic pressure. The complex interaction between phase behaviour and pressure drop calculations can mask the impact of increased injection rate or increased reservoir pressure on wellhead pressure. Changes in phase behaviour and fluid properties can also mask the wellhead pressure from increased hydrocarbon carry-over in the gas stream, where the CO_2 originates from raw gas. Under some conditions, a substantial increase in injection rate can be associated with little increase in injection pressure. Similarly, the fill-up of a target reservoir may not manifest itself by an increase in wellhead pressure. Direct measurement of bottom-hole pressures is required to observe the increase.

Wells injecting into depleted or underpressure reservoirs require attention to rapid expansion and cooling of the fluid during injection. The pipeline and injection pressure are typically higher than a depleted reservoir pressure, meaning the fluid will, as some point in the wellbore, reach a point of rapid pressure change, expansion, cooling and potential for hydrate formation. A downhole choke may minimize and control this expansion. Careful well flow design is necessary!

The introduction of a much cooler fluid may also induce thermal stress fracturing of the reservoir or cap rock. This effect must be considered in the CCS model.

The operator of a CO_2 injection well must have access to fully developed fluid phase envelope calculations for complete understanding of well behavior and the effects of changes to gas composition, pressure, and temperature.

The well operator is responsible for adjusting the wellhead injection pressure to a lower value if a higher density/gradient value fluid is being injected. 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 a potential loss of producible hydrocarbons.

The CCS application must also include the casing age, grade, and collapse pressure of wells within the area of pressure influence 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 injection wells. An appropriate safety factor will be applied to the allowable injection pressure if casing integrity has degraded with age.

> See the **Step-Rate or Mini-Frac Formation Testing** section below for information addressing direct testing for formation fracture pressure.

b) Maximum formation storage pressure

CCS approvals contain a condition limiting the ultimate formation “fill-up” pressure to a specific value. This pressure limit for saline aquifers is typically calculated based on 120% of the virgin reservoir pressure, prior to any production or injection within the reservoir. For depleted pools, the initial virgin pressure is the limit. Unless otherwise stated, the prescribed fill-up pressure is calculated at midpoint of perfs of the injection well(s), 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 to change the perforation interval and a re-calculation will also be done of the maximum reservoir storage pressure value.

This virgin pressure as a basis for storage pressure is initially tested in the first well and is supported by tests in other wells in the same or proximal reservoir. The maximum formation storage pressure limit provides confidence of containment of the CO_2 injected, at a pressure value 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 higher pressure, even if below the formation fracture pressure. The 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, injection must cease. In certain cases, the pressure may fall off below the maximum limit value after a prolonged shut-in time; many months or years. In this case, injection may then re-commence until the ultimate fill-up pressure is reached. Modelling can be used by the CCS project operator to demonstrate that a reservoir will stabilize at or below the storage pressure limit.

Most storage 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 injection reservoir is a concern for drillers who may drill through the zone, and for the containment of fluids.

Where wellbore integrity is a noted concern, the maximum formation storage pressure may be based on a modified casing burst or collapse pressure, with a safety factor applied and a requirement for more frequent casing inspection logging. Compromised wellbore integrity that cannot be mitigated by well workovers or storage operation conditions is a reason to decline approval of an application.

c) Formation Pressure Testing/Monitoring

The initial reservoir pressure of the CCS formation must be measured and reported prior to injection. Where storage is into a depleted hydrocarbon pool, both the pressure at initial discovery and depleted pressure prior to injection are critical values for project management. Periodic measurement of the reservoir pressure in the injection well(s) and any observation wells confirms; 1) that continued injection is viable, the reservoir remaining below the maximum storage pressure limit, and 2) provides information to forecast remaining storage life. Reservoir pressure tests, where the reservoir pressure has not reached a stable state or are not of sufficient quality to extrapolate to stabilized conditions cannot be used predict future storage capacity (“storage reserves”), based on pressure vs cumulative injection volume.

If a pressure test indicates that the reservoir pressure is approaching the fill-up limit, and a cumulative volume versus pressure extrapolation indicates the maximum pressure limit will be reached prior to the next testing date, it is prudent for the operator to schedule the next reservoir pressure test for the predicted date of fill-up. A test with downhole gauges for the duration of the test (a fall-off test) is ideal for the determination of current and extrapolated future pressures, determination of skin, permeability and potentially, a reservoir model. Knowing the fall-off trajectory provides extensive insight into the reservoir behavior and may help to avoid exceeding maximum storage pressure and a potential requirement to flow-back to reduce pressure.

In addition to injection well life cycle management, reservoir pressure data is valuable for use in determination of formation damage (skin), drilling mud-weight programming and well location planning. Typically, reservoir pressure testing for CCS injection wells will be required annually, or at a minimum of every plant turn-around where CCS injection is a dependency of an industrial operation such as a gas plant. If an observation well is available, annual reservoir pressure tests and reports are required.

Between reservoir pressure testing opportunities, reservoir pressure estimates can be determined from wellhead pressure data plus an assumed hydrostatic column minus the friction pressure. Even short shut-in periods can be extrapolated using a Horner plot to estimate the reservoir pressure. The progress report should contain calculation of estimated current reservoir pressures as detailed in the Progress Report requirements. Two-phase flow or going from liquid to dense phase, can introduce errors in the hydrostatic pressure calculation. If recent downhole to surface data is available, this differential value may be used to estimate reservoir pressure between downhole tests.

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 CCS project condition, the maximum average reservoir pressure is normally the pressure measured at the injection well within 60 days of shut-in of the well. To clarify, the well does not need to be shut-in 60 days 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. This value, as an indication of average reservoir pressure, can be discussed with the Regulator and with compelling modelling information a different extrapolation value may be utilized.

As a learning for CCS operation, experience has shown that produced water 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 breach, injection operation can develop an area significantly above the final maximum storage pressure limit, injection rate exceeding dissipation. 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 storage 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 injection well(s), is a proxy for the average pressure in the storage 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 injection wells with large cumulative injection volumes in some clastic reservoirs have displayed limited significant pressure drop beyond the initial 60-day shut-in period. Reservoir pressure values from observation wells in the same reservoir, where communication between the wells has been clearly demonstrated, are also considered in estimating the average reservoir pressure. 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 injection at the well.

Well test results must be incorporated into the CCS storage reservoir model maintained by the proponent. The results of the updated model are included in the next Progress Report. Where the results dictate a need to amendment a condition(s) of the CCS project approval, the BCER must be informed in a timely manner.

e) Wellhead Pressure Monitoring

Approval Orders contain a condition requiring continuous measurement and recording of the wellhead tubing and tubing-casing annulus pressures. As stated, pressures must be measured directly at the wellhead, not the compressor outlet or some other point upstream of the well. "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 for comparison to control system display value. Pressure sensors must be calibrated as per manufacturer requirement and verifiable by deadweight measurement. The alarm system must contain set-points with trigger alarms for both pressures, for operator attention and/or automatic shutdown. Wellhead pressure data files may be requested and audited by the BCER for a period of up to 3 years from date of measurement.

For the tubing, continuous monitoring creates an auditable record that injection has not exceeded the approved MWHIP (maximum well head injection pressure) value. The reported MWHIP on the monthly Petrinex submission is the maximum wellhead tubing pressure sustained for a period of 5 minutes or more.

For the tubing-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 requiring remediation work, prior to becoming a more significant problem. A specified rate of change in pressure, outside of normal operating rate change, is also an advisable alarm setting.

The continuous monitoring must be in place while the well is both 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, continuous wellhead monitoring is no longer required.

f) Wellhead Temperature Monitoring

A CCS approval Order will contain a minimum injection fluid temperature and a requirement for continuous recording of the fluid temperature at the injection wellhead. The measurement point should be as close to the wellhead as possible, downstream of any expansion valves. The intent of the temperature measurement is to verify the fluid stream going into the wellbore does not go below the minimum temperature, which could result in the freezing of ground water or annulus fluid with resulting expansion and damage to the wellbore. A Wellhead Temperature value is required for monthly Petrinex reporting submission. The reported value is the lowest temperature recorded for a period of 12 hours or more.

Alarming for temperatures below 2 degrees C is required.

Production Testing

Prior to an injectivity test or storage injection into a new well completion, the intended storage zone must be production tested for 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(s), with results included in the application and fluid sample analysis additionally submitted via the eSubmission process.

The intention of this testing requirement is to access the presence of hydrocarbons for the proponent and the Regulator to determine if conservation (production) is a viable option.

This production test is not required for a well completed in

- a depleted pool, where no wells have produced from the pool for three or more years or have been subsurface decommissioned (abandoned).
- a saline aquifer where a structurally up-dip well was previously tested with no economic hydrocarbons present.

The proponent may contact the Regulator for exemption from testing in other situations where it can be shown that no economic reserves would be present.

Wellbore Integrity and Logging

Well tubulars, equipment and wellheads must be suitable for CCS service, as outlined in Canadian Standards Association Z741-12 "Geological Storage of Carbon Dioxide", and other applicable references such as API standards.

All porous zones, in addition to the storage zone, must be isolated by cement. For all injection and observation wells completed in the storage reservoir, the permit holder must conduct adequate logging to demonstrate hydraulic isolation of the reservoir. Permit holders may reference AER 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 CCS project application. The BCER 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 storage purpose.

All **new wells** drilled for the purposes of injection or completed for observation in the storage reservoir must ensure that;

- Cement is acid resistant and is not susceptible to deterioration. For further information on cement degradation and hematite, please see "Durability of Portland Cement with and without Metal Oxide Weighting Material in a CO_2/ H_2S Environment" by Y Fakhreldin (SPE paper 149364).
- 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.
- A cement bond log is conducted.
- Hydraulic isolation is established between all porous zones. Often a temperature log following injection test volume 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 Appendix F of this document.

Wellbores containing uphole zones with cement squeeze abandonment may not be suitable for CCS service. Experience has shown that cement squeeze abandonments can be prone to isolation failure. The use of a casing liner and/or multiple packers to isolate former completion intervals in the wellbore is problematic to test for continued seal. Application for CCS service for a well with uphole former completion intervals must adequately address this concern.

For **wells greater than 10 years in age**, the CCS application requires 1) a full-length casing inspection and 2) cement evaluation log. Full length casing inspection and cement evaluation logs only to packer depth may be acceptable if the packer is difficult to remove, is a reasonable distance from the storage reservoir depth and if a temperature log can confirm hydraulic isolation.

Once an injection well is operational, further casing integrity and zonal isolation logging is required at time intervals specified in the approval Order. Logs and interpretation are submitted to the BCER 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 metres to confirm the protection of groundwater aquifers. The secondary purpose is to ensure that fluids are contained within the approved zone, and to protect uphole porous zones. Annual packer isolation tests and following 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.

Through-tubing logging is considered an appropriate method to detect changes in casing integrity. To date, Magnetic Thickness Detector (MTD) logging has been accepted. Alternative logging plans can be reviewed with the BCER before running to ensure the method is acceptable.

In wells that have been operating for a lengthy period of time, the removal of the packer can be costly, time-consuming, and in some cases even damaging to the casing integrity. When tubing is removed during maintenance programs, the BCER will generally accept casing inspection logs run down to the packer depth. This may consist of releasing the packer from tubing using an on-off tool and pulling tubing.

The location of the packer is expected to be within 15m of 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.

Where there is a previously completed formation in the well below the storage formation, a bridge plug and top cement should be set as close as practicable below the injection interval and above any lower porous intervals, while allowing some cellar depth for running logging tools over the complete storage formation if possible. The lower decommissioned zone should meet the requirement of a Level A abandonment, especially where the lower completed formation is overpressured, either naturally or due to injection/disposal use.

Prior to Service Operation - a pressure integrity test is required, the casing or casing/tubing annulus must be pressure tested to a minimum pressure of 7,000 kPa for 15 minutes prior to the commencement of injection operations. A pressure test is considered successful if the pressure does not vary by more than three per cent during the test period.

Hydraulic Isolation Logging

Periodic hydraulic isolation logging is required as a condition of a CCS injection approval. This log should prove that injected fluid is being contained within the intended zone, as well as possibly identifying leaks/storage above the zone of interest, if present. Typically, this will consist of a time-lapse temperature log measured at 0, 30, 60, 90, and 120 minutes after the injection of a cold fluid into the well and compared to a baseline. Refer to Appendix F of this guideline for guidance.

The used of fibre optic distributed temperature survey (DTS), for hydraulic isolation is encouraged. This technology has the advantage of measuring the instantaneous temperature profile over the well, negating the effect of fluid warming while logging tool passes are being run and potentially confusing the results. DTS log profiles can be imaged at any desired time interval to bring added focus.

The submission of hydraulic isolation logs must be accompanied by a log interpretation report from a subject matter expert.

Well Safety Equipment

There are two proven mechanisms that will provide emergency closure of the injection tubing in the event of emergency: A) a surface-controlled, hydraulically activated valve set at shallow depth, and B) deep set check valve (one-way flow). In each case, the safety-valve system is designed to be fail-safe, so that the wellbore is automatically isolated in the event of any system failure or damage to the surface control.

In both circumstances, function testing is required as specified by the manufacturer or API 14B – whichever is more rigorous.

Consideration should be given to the installation of both types of safety valve in a CCS injection well, as each have distinct advantages.

A. **Surface Controlled Subsurface Safety Valve** (SCSSSV) – A downhole safety valve that is operated from surface facilities through a hydraulic control line strapped to the external surface of the production tubing. Two types of SCSSSV are: 1) wireline retrievable, whereby the principal safety-valve components can be run and retrieved on slickline, and 2) tubing conveyed, in which the entire safety-valve assembly is installed with the tubing string. The control system operates in a fail-safe mode, with hydraulic control pressure used to hold open a ball or flapper assembly that will close if the control pressure is lost.

A SCSSSV function test is required at least annually with results reported in the Progress Report to the Regulator. Leak rate determination is also required during the valve function test. The API standards specify appropriate guidelines for acceptable leak limits.

SCSSSV Notes:

- Typically installed 10 to 30m below ground. Any leak in the tubing from below that depth to the top of the packer will communicate to the tubing-casing annulus.
- Provides little protection if both tubing and casing are breached anywhere below the valve depth.
- May create pressure drop just below wellhead that could result in Joule-Thomson cooling and formation of hydrates or freezing of groundwater.
- Wireline retrievable creates a restriction in the tubing, and may need to be removed from the tubing string before installing a downhole tubing plug. Tubing conveyed SCSSSVs do not change the tubing diameter and tubing plugs can pass through.
- Can fail open (if hydraulic line fails to release). This could result in a release in a situation with no other barriers, such as a check valve. If the SSSV is working properly then the back flow through the SSSV would be minimal, based on the shutoff class that was selected. Refer to following link for the shutoff classes: http://en.wikipedia.org/wiki/Valve_leakage

B. **Check Valve** (CV) –
A check valve is placed below the packer on a tubing connection. When closed, it isolates the tubing string.

CV Notes:

- Unlike SCSSSVs, there is minimal documentation around failure rates, making them harder to assess for performance.
- A check valve testing protocol must be developed by the operating company and must deliver outcomes comparable to those delivered by API 14B, with an allowable leak rate specified in Annex A.
- Pulling the valve for inspection must be conducted as specified by the manufacturer; with outcomes provided in the annual Progress Report.

Wellhead Barriers

A CCS Project order requires all CO_2 injection wells have surface wellhead barriers, capable of withstanding vehicle collision, to ensure the wellhead is protected. At a minimum, this barrier should be portable concrete K barriers, similar to those installed along highway edges, 2m or greater from the wellhead.

Emergency Response Plan and Emergency Planning Zone

The **Emergency Planning Zone** (EPZ) for CCS must be calculated at the maximum approved reservoir storage pressure and storage reservoir fluid composition. CO_2 constitutes an asphyxiation hazard due to displacing oxygen. Should the EPZ encompass a populated area, the perforation interval or maximum average reservoir pressure may be restricted to limit the potential flow back rate (deliverability).

Because the 2-phase region or envelope between the dew point and the bubble point lines is narrow, CO_2 requires only a small change in temperature and or pressure to transition from 100% liquid to 100% gas and vice versa. Wellbore flow modelling may be required to understand the implications at various wellbore leak points. As well, CO_2 injection is expected to result in desiccation of connate water in the near wellbore region over time, a consideration for modelling well flow-back fluid composition.

A surface plume dispersion model informs both the EPZ and the Emergency Response Plan (ERP).

An **Emergency Response Plan** (ERP) is required for CCS activities where a hazard exists. The Regulator requires an "all hazards" approach to hazard identification. The purpose of an emergency response plan is to ensure processes and resources are in place to support a prompt and effective response to incidents. The plan must demonstrate how emergency responses will be initiated and coordinated, and fully reflect the risk elements identified in a comprehensive hazard analysis. Permit holders are required to maintain their plans, providing updates as necessary to ensure the actions outlined in the plan address the full range of identified hazards, and that all response resources are sufficient and available to meet such hazards. For example, identification of a sufficiently dense kill fluid, capable of stopping flow from the over-pressured reservoir is required and should be accessible within the response times as identified in the Emergency Response Plan.

Emergency response plans involving CO_2 CCS operations should include the types of failures that may occur with this operation (failures of tubing, packer, casing, tubing and casing, wellhead, safety valve failure, etc.). Each failure type requires documentation of the process that will be followed to regain control of the well. This includes priorities such as responder safety, public safety, and control/containment. The ERP must include a list of response resources qualified in well control procedures who will be contacted in the case of a wellhead or near surface uncontrolled release.

In addition to the risk assessment process, the permit holder is required to develop and implement procedures to mitigate and respond to the risks. This includes staff training and drills, as well as any specialized equipment necessary to promptly and effectively implement the emergency response plan. More information on the Emergency Response Plan requirements can be found on the BCER website in the Emergency Management Manual and by referencing CSA Z246.2.

Prior to commencing injection operations, a full-scale emergency management exercise focusing on a relevant worst-case scenario must be conducted to test critical elements of the plan, staff training and competencies. If necessary, multiple exercises may be held in order for all staff with an emergency response role (including those filling roles in the permit holder's emergency operations center) to participate and validate plan assumptions and training outcomes.

Step-Rate and Mini-Frac Formation Testing

Mini-frac and step-rate testing are direct test methods for determining the conditions under which a formation fracture can be created, extended or opened. To obtain valid data for determining maximum permissible injection pressure, the DFIT or step-rate injectivity test must be performed **prior** to fracture stimulation of the formation.

A **mini-frac or DFIT** (diagnostic fracture injection test) may be used to determine the fracture pressure at the proposed disposal location. DFIT testing is common in tight "nonconventional" reservoirs, however in porous reservoirs more suited to storage the test must be designed, executed and the results interpreted correctly with consideration of the reservoir characteristics. 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.

A **step-rate test** can be conducted to establish the formation propagation 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.
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.

Prior to conducting a step-rate or DFIT test, a Notice of Operation must be submitted through the eSubmission Portal.

Injectivity Testing (Injection Capacity Testing)

A proponent may wish to test the injectivity potential of a zone to establish CCS viability and provide data in support of a CCS application. Injectivity testing is conducted with water, which can be converted by calculation to a CO_2 injection rate.

A water volume of up to 500 m^3 may be used for injection testing, per formation, without prior approval. A volume greater than 500 m^3 requires the submission of an Extended Injectivity Test application. This application is comprised of the portions of the Carbon Dioxide Subsurface Storage Application for which information is available to assess any risks from the proposed injection.

The initial reservoir pressure must be measured prior to an injection test. For large test volumes, a subsequent reservoir pressure measurement, after the conclusion of the test, can assist with determining storage capacity if a rise in pressure has occurred. Pressure transient analysis of the fall-off pressure can also provide values of permeability and skin damage.

As noted in the section titled "Production Testing", an attempt to obtain hydrocarbon inflow must be performed prior to the injection test.

Injectivity testing may not be conducted on open Crown rights, as information provides an unfair advantage in competitive land sales.

Prior to conducting an injectivity test, a Notice of Operation must be submitted through the eSubmission Portal.

Research Activity

Field research can provide valuable data for the development of pilot and commercial projects. This may include surface geology mapping and sampling. CCS research with a cumulative injection volume of up to 500 m^3 of fresh water per well may be exempt from the CCS Project application process. However, normal well permit requirements still apply. Test injection of CO_2 or CO_2 dissolved in water may require an Injectivity Test application and approval. Contact the BCER to discuss.

Note that as per section 24(4) of the *Energy Resource Activities Act,* either ownership of or agreement from the subsurface tenure holder is required to obtain a well permit. Section 24(5) of the *Act* grants the minister authority to approve an application for a permit to drill a well if subsurface tenure or agreement is not held if the well is to be drilled for exploratory or research purposes only.

Note that section 126 of the Petroleum and Natural Gas Act states, in part

Exploration licence for underground storage area

126 (1)A person must not explore for a storage reservoir unless

(a)either

(i)the person is licensed by the minister under subsection (3), or

(ii)the exploration consists only of geophysical exploration, and

(b)the exploration is carried out in accordance with the Energy Resource Activities Act.

Proof of concept related activities, such as CO_2 “catch and release” or injection of the CO_2 into a gas line, activities that do not result in CO_2 injection into the subsurface, are not subject to a CCS project application but may require facilities and pipeline approvals or amendments.

Observation vs Monitoring Wells

An **observation well** may be used to measure formation pore pressure, obtain fluid samples, or seismic data. Wells that are drilled into consolidated formations to a depth of potentially encountering hydrocarbons require a well permit issued by the BCER. An observation well, by definition in the Drilling and Production Regulation (DPR*)*, is prohibited from being used for the production or injection of fluid, other than small volumes associated with testing.

Observation wells, and their sampling and reporting requirements, may be either -
1) listed as a condition within the CCS Project approval, as these wells and their observation data form part of the Measurement, Monitoring and Verification (MMV) plan. 2) receive separate Observation Well Designation approval, upon application, where the observation point is far field and not integral to the operation of the CCS project, to avoid the need to amend the CCS Project approval.

Use of a well for Observation requires subsurface tenure of the formation(s) completed (perforated or open hole) in the well. Where the method of observation data gathering does not require completion of the well, for example DAS (distributed acoustic sensors) fiber optic cables attached to the outside of the casing on a well, subsurface tenure of zones being observed is not required. However, note that ERAA section 24 specifies that a well permit holder be the owner, or have agreement with the owner, of some type of subsurface tenure, which may be for other formation(s) than those being observed.

Monitoring wells are usually small diameter, often lined with PVC pipe or screen, drilled to shallow depths and terminated within overburden. These shallow boreholes used for water sampling are deemed monitoring wells and are not subject to the requirements of a well permit issued by the BCER.

Shallow monitoring wells proposed/required are listed in the CCS Project approval Appendix, with sampling and reporting requirements determined by a BCER hydrologist. Additional details are contained under the later section of this document “Groundwater Monitoring Requirements”.

Baseline Values

The measurement, monitoring, and verification (MMV) of a CCS project may require baseline values of native CO_2 at the surface and near surface environments, to verify and provide assurance of CO_2 containment. This is especially the case at CCS locations outside of storage in the deep section of the Western Canadian Sedimentary Basin in NE BC.

Natural CO_2 levels are measured in soils and overburden at various depths and in usable water aquifers via monitoring wells. A program of periodic samples can account for potential season changes to CO_2 levels, providing a baseline for identification and investigation of any later anomalous values detected.

The CCS project applicant is responsible for the identification of any need for baseline measurements and monitoring and inclusion of such plan in the application.

Hydraulic Fracture Stimulation

Reservoirs are selected for CCS based on a natural ability to accept and store injected fluids at an injection pressure below the formation parting pressure (“fracture pressure”). Continuous injection above the formation parting pressure has the potential for fluids to migrate out of the storage formation, and/or significantly beyond the forecast plume boundary to unexpectedly contact existing and drilling wells or faults. A CCS approval limits the operating surface wellhead injection pressure below the value that will induce fractures, accounting for the addition of the fluid gradient hydraulic pressure column and friction loss to the depth of injection, with a minimum 10% safety factor applied.

However, a completed wellbore interval may require a controlled acid or hydraulic fracture stimulation to bypass formation damage caused by well drilling/cementing operations or reservoir effects from injection, to increase connectivity. Any stimulation **prior to application** for CCS use must be done before hydraulic isolation logging that is submitted as part of the application.

Upon application approval, a CCS project approval Order includes a condition prohibiting hydraulic fracture stimulations of project wells, without prior BCER 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.

Permit holders are cautioned to design and limit fracture stimulations to remain contained within the disposal formation. A request for approval of a fracture stimulation, post-CCS Project approval, must be submitted to the Reservoir Engineering branch. This request consists of the fracture operation plan, the intended size (tonnes of proppant to be placed) and maximum treating pressures, together with results from fracture simulation model software. The BCER usually requires the permit holder to conduct a hydraulic isolation log post-stimulation and prior to the resumption of injection (except for a small volume of fluid to perform the log test) to confirm isolation and integrity of the bounding formations.

Horizontal or Highly Deviated Wells

The BCER may consider injection into wells that are horizontal or highly deviated in the storage reservoir. Extra factors must be considered for these types of wells. Full-length integrity logs are expected for all injection 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 BCER 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 storage reservoir. If the zone is hydraulically fracture stimulated, care must be taken to ensure that the stimulation remains in-zone.

Seismicity

Injection of fluids into the deep subsurface has the potential to cause induced seismic (IS) events. IS requires a pre-existing fault, at a receptive depth and at a pre-existing stress state. A change in formation pore pressure may result in fault movement.

Most injection wells in BC have not resulted in measured seismic events, however a limited number of injection/disposal wells have been linked to induced seismic events. The majority of such events are of magnitudes that cannot be felt by humans at the surface. IS events related to fluid injection that are felt at surface have been modelled to be a result of fault displacement measured in centimeters.

The CCS proponent is required to provide a thorough geologic description of known or conjectured faults within the area that will be contacted by the reservoir plume to the time of stabilization. The traits of such faults must be assessed for the risk of IS and documented in the application.

A demonstrated pattern of cause and effect of seismic events to injection operations may result in modification to the CCS approval, limiting injection pressure and/or rate, or ceasing storage injection, to mitigate further seismic activity.

Oversight of seismic events is achieved through seismometers around the injection well locations, in a pattern that allows for accurate magnitude and location detection (including depth). The detection range will be specified in the Order. Existing seismic arrays may be suitable to meet this monitoring requirement in some areas.

Ground motion detection near CCS assets may also be required through installation of accelerometers at or near a well site, however this is not mandatory.

Further details regarding accelerometer data:

1. Ground Motion Monitoring Requirements were established by the Regulator at frack sites as indicated in Industry Bulletin 2016-19. www.bcogc.ca/node/13257/download
2. The guidance for collection of accelerometer data is detailed in the attachment and here: http://www.bcogc.ca/node/13256/download
3. The intent for accelerometers at CCS injection wells is to understand the ground motion near these critical wells; allowing for action to be taken if the motion is severe. Large motion should trigger an operator to proactively review the injection well integrity data such as casing and tubing pressure. As well, an inspection and documentation of surface equipment and casing vent assessment would be prudent.
4. The accelerometer (ground motion) data will be required for submission when a magnitude 3.0 event or greater is detected within 5 km of the injection well. The Regulator will contact CCS operators to provide the time of the event. The operator will submit the data in csv format from 30 seconds before the observed event and 60 seconds after. (csv form)
5. Currently, accelerometer data is accessible to the public through a FOI request. However, accelerometer data is considered well data and may be made available on the BCER eLibrary once the IT distribution capacity is established.

Section 21.1 of the Drilling and Production Regulation requires reporting to the BCER any seismic events with magnitude 4.0 or greater, or felt ground motion, within 3km of an operating injection well. Injection operations must be suspended if the seismic event of magnitude 4.0 or greater is attributed to the operation of the well.

A website of all events over magnitude 1.5 can be found on the BCER website here.

Annular Pressure Integrity Test and Packer Isolation Testing

Before injection operations begin, a **wellbore 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 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 injection 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 or section 9.1.3 of Oil & 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 a pressure of 1,400 kPa.

Groundwater Monitoring Requirements

CCS project applications undergo a multidisciplinary review by BCER Reservoir Engineering, Geoscience, 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 and sensitivity. For approved CCS projects, the approval Order contains standard conditions for well monitoring and reservoir and groundwater protection. Based on the hydrogeological risk review, additional site-specific conditions may apply. A CSS project application may be denied based on the results of the hydrogeological risk review.

The hydrogeological risk review involves compiling summary documentation on:

- injection well information and construction details
- storage reservoir characterization, including well testing data
- relevant geological formation information including logging data
- 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);
- 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 BCER 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 CCS wells if:

- concerns regarding wellbore integrity and/or groundwater sensitivity are identified; or
- the top of the storage reservoir is below, but within 100 m of, the Base of Usable Groundwater (as determined by BCER staff using the “geological marker based approach” which applies the definition of “deep groundwater” from the Water Sustainability Regulation section 51 found here Water Sustainability Regulation.

(If the top of the storage reservoir is shallower than the base of usable groundwater determination, the application will be denied.)

The above framework is applied allowing for professional judgment by BCER staff. Specific requirements relating to the number of monitoring wells, locations, depths, sampling frequency, analytical parameters, and reporting will be determined by the BCER 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.

Facilities & Pipelines

Applicable legislation includes requirements for the design, construction, maintenance, operation, suspension, and decommissioning of facilities and pipelines. A facility permit application must be submitted to the BCER for surface equipment associated with a CCS project. The permit process requires consultation and notification within the EPZ or within 3 km. If a pipeline for CO_2 is required, a pipeline permit application is required. See the applicable sections of the BCER Permit Operations and Administration Manual.

Amendments to facilities approvals, for equipment or pipelines to accommodate carbon dioxide capture and transportation, are made to the BCER Facilities & Pipelines department.

Notification and Reporting

A CCS Project approval specifies that a BCER field inspection occur with six weeks of commencement of operation. This site inspection includes verification that a copy of the CCS Project approval is available onsite, and that equipment and instrumentation is installed and operating in accordance with requirements, for example, continuous measurement and recording of wellhead injection pressure and temperature.

Once injection operations begin, a change of well status to active (ACT INJ) is required in the Petrinex system by the 19th day of the month following the date of initial injection. The status change must be done at least one day prior to volumetric reporting.

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 injection occurs into the well, a volumetric report must be filed in Petrinex, reporting total injection hours, volume, maximum wellhead tubing injection pressure and minimum wellhead temperature. The volumetric report is due on the date posted on the Petrinex reporting calendar, usually by the 20th day of the month following injection. Should the well operate seasonally or be shut-in temporarily, select the "inactive" checkbox. After 12 inactive months, the well status will be required to change to suspended. Instructions are available on the Petrinex website.

A change in operations, such as at start-up or a rate change, can result in momentary pressure spikes. The monthly reported wellhead pressure is the maximum pressure, sustained for a period of a minimum of 5 minutes continuous duration during that month. The minimum temperature value reported should be the lowest temperature recorded for a period of 12 hours or more.

MMV (Measurement, Monitoring and Verification) & Progress Reports

Measurement, monitoring, and verification is a term frequently associated with CCS projects. Injection of CO_2, acid gas, or produced water in oil and gas producing areas is a mature technology and the MMV expectations have become a matter of routine oilfield oversight. For sequestration projects in unproven areas with less geologic information and historic conformance data, MMV considerations may require additional baseline and follow-up activities. MMV requirements are risk-based site-specific for all reservoirs and project types.

The MMV program begins at the project evaluation stage, to ensure the reservoir and wells are appropriate for CCS. Specific required monitoring, measurement, operating limits, testing, and reporting over the operating life of the project verify ongoing containment. Post-injection, any additional monitoring and decommissioning requirements ensure the CO_2 will remain sequestered for geologic time. The MMV program also provides assurance for any applicable carbon credits or off-setting programs associated with the project.

MMV starts with the application review and continues throughout operations and post-closure, as outlined in the following points. These summarize items stated in other portions of this document and are provided as a convenience for those interested in this specific aspect of a CCS project:

- Professional reliance required of a proponent making the application.
- Reservoir modelling by the proponent of the reservoir plume to the point of eventual stabilization, with updates as new data is available.
- A thorough multi-disciplinary review of the project and specific wells by Regulator professionals to confirm suitability for the proposed project.
- Approval conditions to maintain the integrity of the storage reservoir;
    - no hydraulic fracture stimulation without approval.
    - an injection pressure limit to prevent hydraulic fracturing.
    - a maximum storage pressure limit to ensure containment for geologic time.
    - observation well(s) approval and reporting as required, in the storage formation and/or formations above.
- All injected CO_2 must be metered, and the injected volume and wellhead injection pressure and temperature reported on a monthly basis, via the Petrinex reporting system.
- The injected gas must be sampled, and the sample analysis submitted to the BCER via the eSubmission process, at pre-determined intervals.
- Ongoing reservoir pressure tests must be conducted and submitted to verify the storage limit has not been reached and to estimate the remaining storage volume of the reservoir.
- Subsurface safety valve function and leak testing at least annually, or more frequently if required by the manufacturer.
- Hydraulic isolation logging must be conducted and submitted a minimum of every 5-years, to confirm fluid containment in the reservoir.
- Well integrity logging conducted and submitted a minimum of every 10 years, to confirm continued suitability of the well for injection service.

- Annual packer isolation tests and surface casing vent flow tests conducted and submitted to confirm mechanical integrity of the well.
- Progress Reports submitted to the BCER every 6-months, summarizing activities during the report period and observations of behaviour in relation to expected performance.
- Updating of the reservoir plume model by the proponent as additional data becomes available. Submitted to BCER with Progress Reports, or sooner if a significant amendment.
- Reporting of any well completions, workovers, repairs or maintenance operations to the BCER following the conclusion of the activity.
- Ongoing field inspections by the Regulator.
- Post-injection ongoing reservoir monitoring, via injection and monitoring wells, to confirm trending to reservoir stabilization.
- Post-injection continued long-term operation of shallow monitoring wells, if determined that further data is of value.
- Well decommissioning meeting Level A requirements to ensure competent sealing of the formation and well.
- Post COR (Certificate of Restoration, Part 2) the site remains subject to future audit inspections and reporting of any issues.

Other conditions appropriate for the circumstance may apply that are not listed above.

A condition of a CCS Project order is the submission of Progress Reports to the BCER at regular intervals over the operating life. Report requirements appropriate for the specific project will be itemized in the Project approval. The content of the report generally aligns with those listed in the Acid Gas Disposal Progress Report Requirements document Acid Gas Progress Report Guideline. The normal report interval, specified in the approval, is twice per year, for the calendar periods January to June, and July to December.

Progress Reports contain data which verifies the CCS Project is operating in compliance with all conditions of the approval, and that the subsurface performance is following modelled behaviour. This document is a report of Measurement, Monitoring and Verification (MMV). These Reports give the project operator and the Regulator a chance for regular review.

Where performance is not meeting expectations, the report must include an explanation, and if warranted, an update to reservoir modelling. Where an amendment to the project approval is required to mitigate an identified issue(s), this change may be initiated by the proponent as an application to amend, or in some circumstances be proactive by the Regulator.

As outlined in the “Amendments” section of this document, a program of monitoring and reporting may extend beyond the period of active injection.

Project Amendment

The CCS Project approval may be amended multiple times over its operational and monitoring life. An amendment may be initiated by the project operator or by the BCER based on a need and supporting evidence. The cover letter to the amended order, issued by the BCER, documents the rationale for changes.

Typically, an amendment will be to a specific condition(s) of the approval. A request for a revised project area may be due to an updated reservoir plume model based on new information. Other examples of requirements for amendment include a proposed change in an operation that would contravene an existing condition. In all cases, the request for amendment must be supported by provided data and rationale, and not have a negative impact to well or formation integrity. The addition of injection, observation, or monitoring wells also requires an amendment to the Project approval.

The content of an application to amend an existing approval is confined to the items of the specific request and does not require a complete new application with all items listed in the Application Guide.

Once operations have ceased at a reservoir project, the approval is normally cancelled. However, CO_2 storage may require an ongoing phase of monitoring to satisfy the MMV program. Therefore, once injection has ceased, a project amendment may be issued which continues conditions for monitoring, testing, and reporting for a defined period.

Decommissioning (Abandonment) Considerations

A final reservoir pressure is required prior to abandonment, to confirm the effect from storage operations. This pressure provides a valuable data point for understanding reservoir capacity, and planning any future well operations in the area that may encounter this reservoir.

Carbon dioxide storage formations are required to be abandoned in accordance with the requirements for Level A intervals as described in BC Well Decommissioning Guideline. A Notice of Operations, including the proposed plugging program and a current wellbore diagram, must be submitted 7 days prior to field work. Decommissioning (abandonment) programs are subject to a Regulator review, with the permit holder contacted only if any concerns are identified.

The Regulator may require the permit holder to monitor the well pressure for a period of time between downhole and surface decommissioning to verify an effective downhole seal.

Approval Termination

A CCS Project where injection wells that have been inactive or suspended for a period of more than two years, that is not in an approved monitoring phase, are reviewed by the BCER for potential CCS Project approval termination. Notification of intent by the BCER provides the operator an opportunity to provide reason(s) the approval should not be terminated.

This satisfies records management and ensures a renewal of injection does not occur without prior re-application and assessment.

Appendix A: Details for Approval Order Conditions

This appendix provides examples of typical approval Order conditions, with the rationale for inclusion. For some items, additional details are included within the body of this Summary document. Approval Orders also contain a "Regulatory Advisory" section, as an awareness of specific regulation sections to which the wells are subject.

MONITORING

Continuously measure and record the wellhead of casing and tubing pressure – The tubing and casing-tubing annulus pressures must be continuously and electronically monitored and SCADA enabled to ensure:

- For the tubing pressure, ensure the injection pressure does not exceed the approved maximum.
- For the casing-tubing annulus pressure, this is the first line of wellbore integrity detection and ensures annulus containment. It is worth noting the casing pressure may be sensitive to changes in injection rates and temperature. Because casing pressure data should be useful for detection of tubing cracks or holes, packer leaks and casing breaches, **it is important to closely monitor the annular pressure** reaction to changes in injection rate and corresponding pressure.
- **Annulus Pressure Cycling** – Observations have been made of increasing annulus pressure when well injection rate decreases or the well is shut-in. This is a result of the natural geological warming process. The increased annulus pressure is often bled off. When injection begins again, the relatively cool fluid lowers the wellbore temperature and the annulus pressure decreases. These operational changes result in annulus pressure cycling. Awareness and understanding are important for correct interpretation of pressure trends and assurance of wellbore integrity.

Alarm the annulus pressure monitoring system to indicate when casing pressure varies outside a normal range - Casing pressure may remain steady over time, or change gradually, and may become easy to ignore. Wellbore integrity is ensured through careful monitoring of the annulus pressure. This condition brings attention to monitoring of the casing pressure. The rate of change in pressure may be programmed as a warning, as well as minimum and maximum values.

Cease injection upon reaching a maximum formation pressure of XX,XXX kPaa, measured at MPP – The formation pressure test must be conducted during each planned plant shut-down. If the test duration is not sufficient to determine the average reservoir pressure, then a pressure transient analysis must be done. See Summary Document section CCS Approval Requirements and Conditions part d, on Pressure Transient Analysis expectations. A reference depth for the pressure value is stated, usually the mid-point of perforations (MPP), that the measured depth pressure must be corrected to for comparison to the limit.

Monitoring of the reservoir plume – Monitoring of the CO_2 plume may be accomplished through testing of wells completed in the same formation as the injection well. If the nearest well(s) do not belong to the CCS Project owner, it is advised to make arrangements for fluid sampling and/or reservoir pressure testing. Though plume growth may be modelled as radial, impacting the nearest wells first, geologic structure and high permeability streaks may cause fluids effects to be more pronounced in preferential flow pathways, also warranting monitoring of further distance wells.

Collect fluid sample and submit lab analysis twice annually – For the storage injection well(s), report the lab gas analysis to the well permit number, even if taken at the compressor outlet. Gas analyses will only become accessible to industry if they are reported to a well number. The progress report must also contain a history of all sample analyses. Again, best efforts must be made to collect samples and have them analyzed in the neighboring wells.

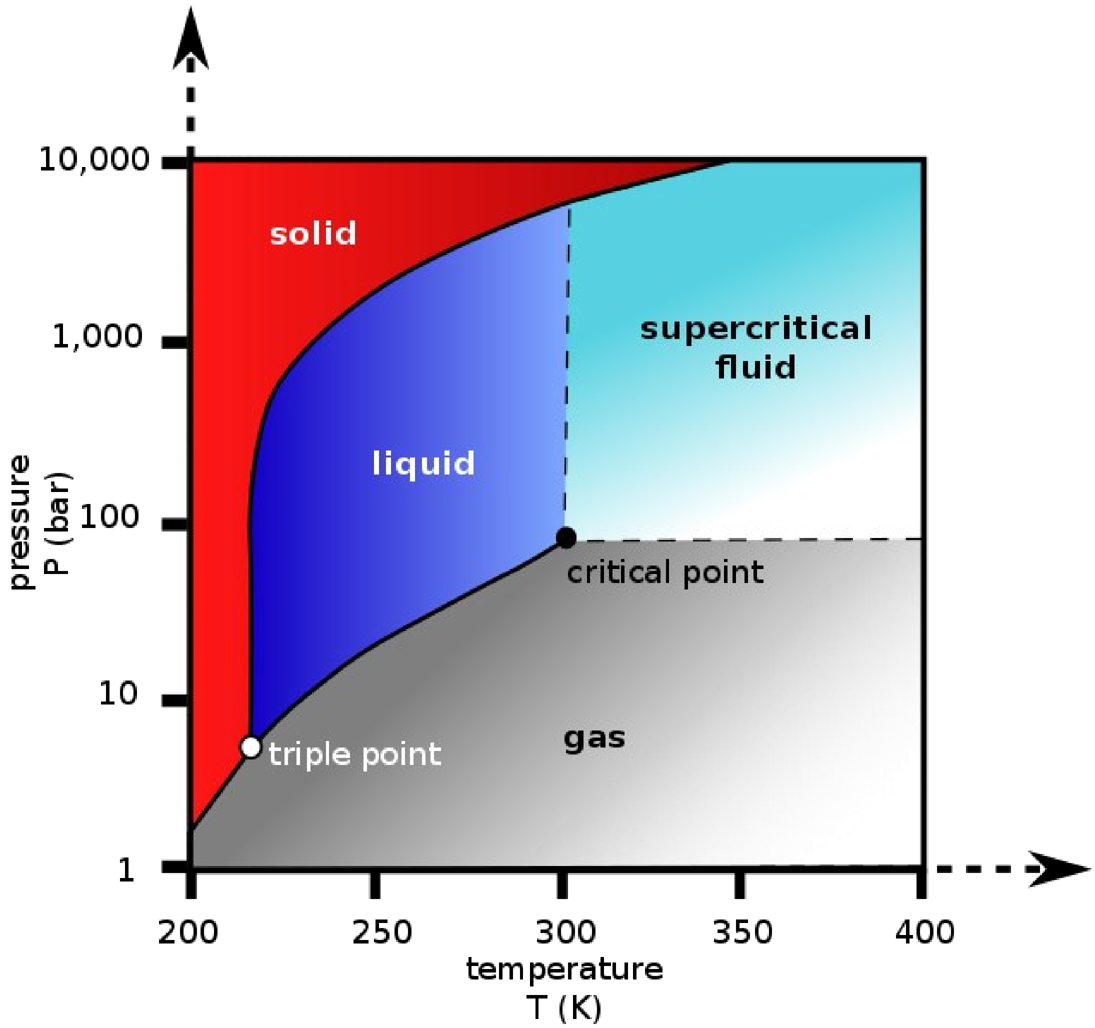
WELL INTEGRITY

Corrosion and Frost Protection – Annulus must contain corrosion-inhibited fluid and at least 2 metres of diesel or equivalent freeze resistant fluid (frost protection) top-up to ensure the wellbore is corrosion and freeze protected.

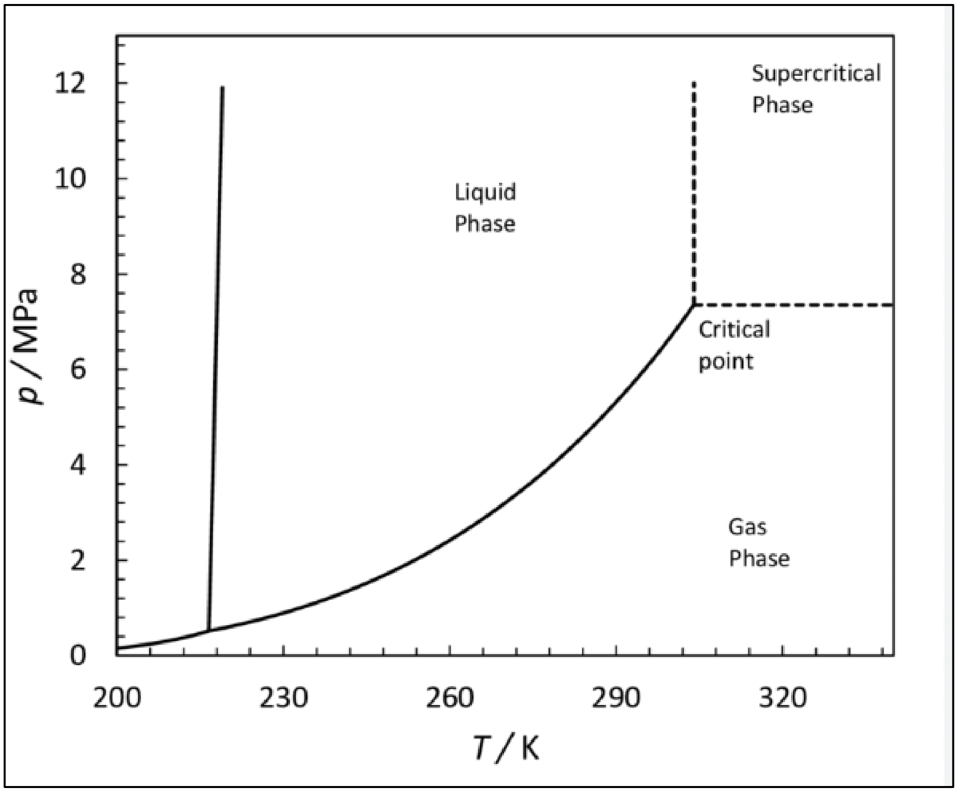
Conduct function testing of SCSSV as details in API 14B, or as recommended by manufacturers, whichever is more rigorous. In some cases, the manufacturer may recommend a frequent but simple testing such as a monthly open and close cycle of the valve. In this case, the API 14B recommendations would be more rigorous as the testing requirements include a stable shut-in and a leak test.

Conduct function testing of check valve - At a minimum, permit holders must follow manufacturer's recommended testing procedure and frequency. See recommendations in API14B.

Appendix B: Phase Diagram



Carbon dioxide pressure-temperature phase diagram
Source: Wikipedia



Hydrate curve includes the points where hydrates might form but is based on the presence of free water. The storage injection stream typically does not contain free water, but if the well was flowed back, it may contain free water from the formation. Longer term injection with higher volumes may result in a water-free area in the reservoir around the wellbore due the desiccant properties of injection.

The operator of a CCS well must have access to fully developed fluid phase envelope calculations for complete understanding of well behavior and understanding of the effects of changes to operating gas composition, pressure and temperature!

Appendix C: Measurement and Safety Equipment (Facilities)

The start-up of a new CCS injection well triggers a BCER initial site inspection, to ensure all applicable regulations and standards have been applied, including the conditions of the CCS Project approval Order. CCS wells and associated facilities are also subject to regular inspection over the life of the asset.

Inspections and Audits

- 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 or drift errors.
- A wellhead tubing pressure maximum limit is defined in the Approval. There should be a mechanism for a high pressure shut down which will ensure the maximum tubing pressure is not exceeded.
- Flow meters require calibration and calibration tags. The BCER BC Measurement Guideline contains additional details.
- Ensure staff include ALL calibration and instrumentation, measurement, and safety system maintenance in the SAP maintenance planner.
- Injection wells off the plant site should have a daily visual inspection.
- A flow control valve is not an emergency shut-off valve, must be separate.
- Each well operator should be responsible for their own measurement, ESD operation, metering, high- pressure shut-down etc. Key requirements for CCS wellhead flowline ESDV would be:
    - Tight shut-off Class VI (ANSI/FCI 70-2)
    - Fail safe
    - Quick closing
    - Dual seal
    - Full port
    - NACE specification
    - Low temp service.

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 Regulator should include the graphs of casing pressure vs. time obtained during Step 4 and Step 6.

   Packer Isolation Tests must be submitted exclusively through the Packer Isolation Test selection under the Well Integrity option in eSubmission. For further details please refer to INDB 2020-14 https://www.bcogc.ca/news/packer-isolation-test-pit-report-submission-changes-indb-2020-14/

Appendix E: Stress Considerations in Determination of Maximum Wellhead Injection Pressure

Definitions/Terminology

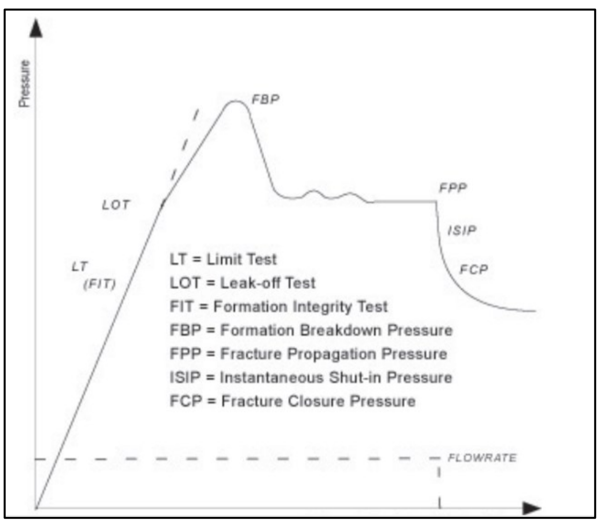
- **Formation Fracture Pressure:** This term can be ambiguous in that is often used to indicate the minimum pressure at which the formation may break or crack (minimum stress or fracture closure pressure) but it also may be the pressure at which there was a significant breakdown of the formation or creation of a fracture network or it may mean the ISIP of the formation or it may mean the FPP (fracture parting pressure). In this document, Formation Fracture Pressure refers to the minimum pressure at which the formation will fracture.
    - **Fracture Closure Pressure (FCP):** This is the same as minimum stress and formation fracture pressure
    - **Minimum Stress:** In this document, minimum stress is the same as FCP and formation fracture pressure
- **Fracture Pressure and Fracture Gradient:** "Fracture pressure", and its depth normalized value, "fracture or frac gradient" are terms that have been used for different purposes in the hydraulic fracturing industry. In this document, fracture pressure is a term used to quantify the pressure required to open or create fractures. Fracture gradient is this pressure divided by the true vertical depth where the pressure is applied and is used to normalize the data to make it comparable to other wells at varying depths
- **Formation Breakdown Pressure (FBP)**: This can be described as the pressure at which substantial fractures are generated (creation of a fracture network). On the plot below, this is the point at the peak showing a sudden drop in pressure as fluid enters the newly formed fractures. This will not be the value used for determination of maximum wellhead injection pressure.
- **Fracture Parting Pressure (FPP):** Determined during a step-rate test, the pressure at which the formation opens and applied pressure leaks-off. A **change in slope on the pressure curve will occur, due to a release of the build up pressure -** if the parting pressure has been reached and exceeded.
- **Fracture Propagation Pressure (FPP):** In order for a hydraulic fracture to propagate, fluid pressure must cause the formation to fail. If the flow resistance is high - due to high viscosity or a long or narrow hydraulic fracture - more pressure is required to propagate the fracture. In addition, if the formation is more difficult to break, more pressure is needed to propagate the fracture. This means that: 1) the *propagation pressure* is higher than the *fracture pressure (closure)*; and 2) the *propagation pressure* varies with the fluid viscosity and the ability to break the formation (grow the fracture).
- **Instantaneous Shut-in Pressure (ISIP):** When pumps are shut off and the excess pressure due to the effect of fluid viscosity and the friction are no longer present, the pressure at that point is the ISIP. Picking ISIP from a DFIT curve is notoriously subjective but is often used to calculate the minimum stress. The result can be highly variable. The ISIP value should be close to the FPP.

Stress Considerations for MWHIP on Disposal wells

When an approval Order is issued for operation of a disposal well, a condition in the Order establishes a maximum wellhead injection pressure (MWHIP). Establishing an MWHIP ensures the formation fracture pressure is not exceeded during disposal operations. The formation fracture pressure is the pressure at which the formation may part, open, split or breakdown. In the past, the formation fracture pressure has been determined by conducting a Diagnostic Fracture Injection Test (DFIT) and using the instantaneous shut-in pressure (ISIP) as a proxy for fracture pressure. Or alternatively, the interpretation of formation parting pressure from a step-rate injection test. However, recent publications on theoretical maximum and minimum stress values have resulted in a review of the Regulator's process for determination of the MWHIP. As well, interpretation of ISIP and closure pressure (FCP) are subjective, variable and open to interpretation, furthering the uncertainty. There are currently various methods for determination of closure (Baree or McClure), with the results varying by approximately 10%. Because the DFIT closure pressure may be disputable, it is only one consideration in the assessment of minimum stress and maximum wellhead injection pressure.

As mentioned above, a DFIT (see figure 1) is often the process used to determine the fracture closure pressure/formation fracture pressure (or minimum stress). To date, the Regulator has relied on the ISIP value from the DFIT or the FPP (fracture parting pressure) value from a step-rate test. However, the ISIP and FPP values are greater than fracture closure (minimum stress). It's also possible ISIP may be greater than vertical stress (Sv). This could have implications such as opening of existing vertical or horizontal fractures in the rock, especially in circumstances where there are natural fractures, bedding plane discontinuities or where the pressure continuously exceeds the minimum stress, reaching far-field from the wellbore.

DFIT and Step-rate Charts



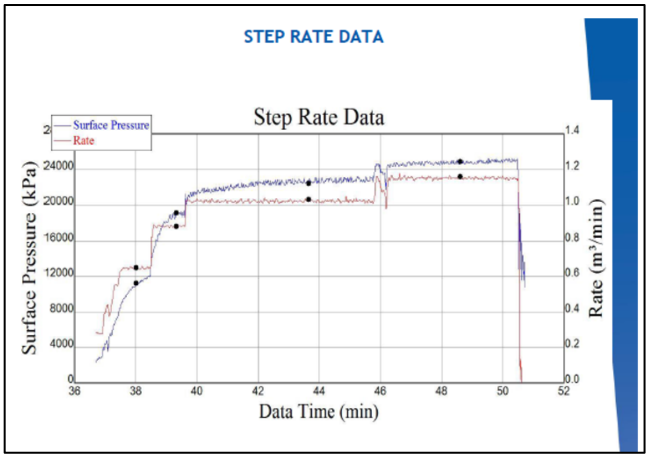
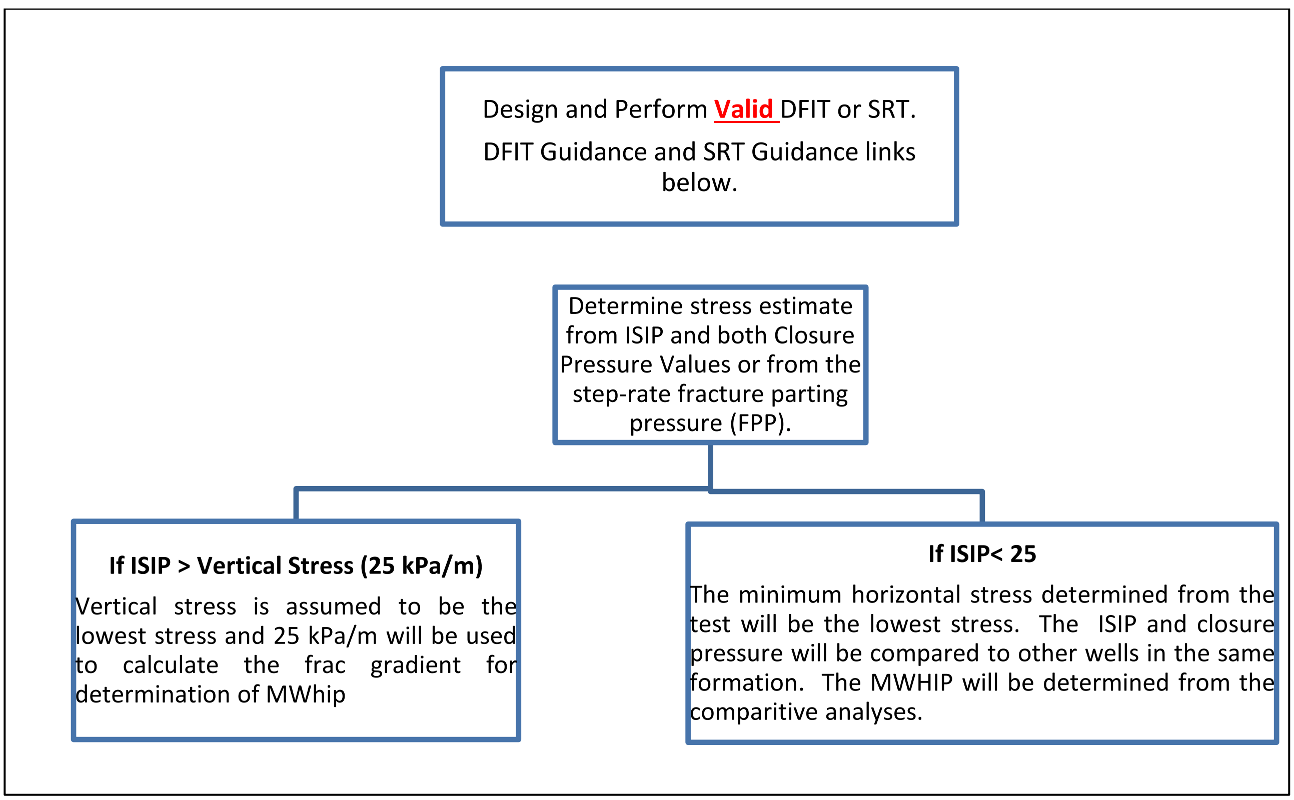


Figure 1 – Typical Minifrac (DFIT) and Step-Rate Pressure Plots

When the ISIP or FPP exceed the published Sv values in the area, an in-situ or local determination of Sv may be necessary to provide certainty for the minimum stress at this site.

As noted above, interpretation of ISIP and FCP are subjective and dependent on the analysis method. It is prudent to use consistent and well-supported process for determination of the maximum wellhead injection pressure. Below is a flowchart displaying the OGC process for this determination.

Flow chart for decision making



[DFIT Guidance]

SRT Guidance

Determination of Sv or Overburden Stress

Source: Pressure, Stress and Fault Slip Risk Mapping in the Kiskatinaw Seismic Monitoring and Mitigation Area, British Columbia – Final Report

Vertical stress is calculated by integrating a density log (or bulk density log) to quantify the weight of the overburden according to

$$S_V = \int_0^z \rho(z) g dz$$

where z is the true vertical depth of interest, r(z) is density as a function of depth and g is the gravitational constant. [Note that if calculating vertical stress in an offshore context, SV must be corrected for the water depth.]

Review table of the Sv values published for BC

Study Authors	Sv Values (kPa/m)	Depth (m)
Grasby et al (2012)	23.5 to 25	1000
Ali Mahani (2020)	24.9 to 25.8	Lower Middle Montney
Enlighten Geoscience (2020)	24.6 to 25.5	Lower Middle Montney
Geoscience BC Petrel (2019)	24.5	varying

References

Bell and Grasby 2012 - The stress regime of the Western Canadian Sedimentary Basin

Enlighten Study – Pressure, Stress and Fault Slip Risk Mapping in the Kiskatinaw Seismic Monitoring and Mitigation Area, British Columbia

Geoscience BC Report Wastewater Disposal in the Maturing Montney Play Fairway of NEBC

Ali Mahani et al 2020 - A Systematic Study of Earthquake Source Mechanism and Regional Stress Field in the Southern Montney Unconventional Play of Northeast British Columbia, Canada, Seismological Research Letters, 2020

Robert Bareee, Valencia Barree, David Craig Holistic Fracture Diagnostics

Robert Hawkes, Irene Anderson, Robert Bachman, A. Settari Interpretation of closure pressure in the unconventional montney using PTA techniques

Appendix F: 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^{o}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 m^3 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 15m^3 of fluid, at least 15^{o}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 BC Energy Regulator within 30 days of the run date.

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)