	Ministry of Energy and Climate Solutions **Issued: May 20, 2025** **Revised: N/A**	***Low Carbon Fuels Act*** **B.C. Low Carbon Fuel Standard: Carbon Capture and Storage "What We heard" Report**

B.C Low Carbon Fuel Standard: Carbon Capture and Storage "What We Heard" Report

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Executive Summary

The British Columbia Ministry of Energy and Climate Solutions (the Ministry) conducted public and stakeholder engagement on the Carbon Capture and Storage (CCS) Intentions Paper from December 16, 2024, to February 13, 2025. The paper outlined proposed requirements under the British Columbia Low Carbon Fuel Standard (BC LCFS) for the use of Carbon Capture and Storage (CCS) and Carbon Capture, Utilization, and Storage (CCUS) to reduce the carbon intensity (CI) of low carbon fuels. Fourteen formal submissions were received, comprising 103 individual comments from industry, other governments, non-governmental organizations, and members of the public.

Stakeholders expressed broad support for the intent to recognize CCS and CCUS as compliance pathways under the BC LCFS. Several commenters welcomed the precedent of awarding credits for CCS projects located outside the province, acknowledging the atmosphere as a shared resource. Stakeholders also encouraged alignment with existing regulatory frameworks, such as Environment and Climate Change Canada's Clean Fuel Regulations (CFR), the United States Environmental Protection Agency (U.S. EPA) Class VI well program, and regional CCS protocols.

Key areas of feedback included requests for greater clarity and flexibility in eligibility criteria (such as post-injection reservoir pressure, pore space access), the treatment of CO_2 utilization in lifecycle assessments and the exclusion of upstream or Scope 3 emissions. Many submissions emphasized the importance of site-specific Monitoring, Measurement, and Verification (MMV) plans, proportionate post-injection monitoring obligations, and transparent Verification requirements that accept equivalent engineering or geoscience credentials from other jurisdictions.

Several stakeholders recommended expanding crediting to include CCS applied to fossil-derived base fuels, as well as new fuel pathways such as Direct Air Capture (DAC) combined with Enhanced Oil Recovery (EOR). These expansions were seen as opportunities to support emission reductions and enable decarbonization investments. Other stakeholders proposed stricter safeguards such as extended monitoring periods, performance thresholds to limit emissions from capture and transport, financial assurance mechanisms (e.g., trust accounts or insurance) and penalties for over-crediting.

Table of Contents

Introduction

The Government of British Columbia is developing a Carbon Capture and Storage (CCS) protocol for the BC LCFS. To support this effort, the Ministry of Energy and Climate Solutions drafted and published an Intentions Paper on December 13, 2024, and conducted engagements with industry, government, non-government and other organizations between December 16, 2024, to February 13, 2025.

The Ministry of Energy and Climate Solutions appreciates the time and efforts taken by stakeholders to provide feedback and support the Province's transition to a low-carbon economy.

This document summarizes the feedback received on the CCS Intentions Paper, with the official CCS protocol expected to be finalized in 2025 following consideration of the feedback received.

The structure of this document follows the same sequence as the Intentions Paper.

Carbon Capture and Storage Intentions Paper

The intentions paper outlines the requirements for fuel producers, and fuel suppliers who use carbon capture and storage (CCS) and carbon capture, utilization and storage (CCUS) to reduce the carbon intensity (CI) of fuels. The document covers eligibility criteria, lifecycle modeling considerations, monitoring, measurement protocols, and risk assurance mechanisms.

The main changes the ministry plans to implement include:

1. The clarification of boundary conditions used in lifecycle assessment modelling and the quantification of emission sources, sinks, and reservoirs that must be included.
2. The introduction of a discount factor to account for long-term risk of leakage/reversal.
3. The requirement for an annual sequestration project report, consisting of two sections, volumetric CO_2 reporting, and risk identification and mitigation.

Summary of Feeback

During the engagement period, the Ministry of Energy and Climate Solutions published the intensions paper on its website, notified interested parties and invited feedback. The ministry received 14 formal submissions comprising 103 individual comments. These included input from:

- Fuel producers and importers.
- Energy infrastructure developers.
- Carbon capture technology providers.
- Trade and industry associations.
- Engineering and verification consultants.
- Academic and research institutions.
- Environmental and climate advocacy organizations; and
- Members of the public.
- Government agencies

Respondents provided feedback from both Canadian and international perspectives, including representation from projects and regulatory regimes in the United States and other jurisdictions.

Table 1 Summary of submissions and individual comments

Party	Submissions	Individual Comments
Industry	10	82
Non-Government Organizations	2	4
Government	1	4
Other	2	17
Total	14	103

The key sections identified in the feedback received are consistent with the intentions paper as follows:

1. Carbon Capture (Utilization) and Storage
2. Eligibility/Criteria
3. Project Periods
4. Risk Assurance
5. Project Description
6. Sources, Sinks and Reservoirs
7. Quantification and LCA modelling
8. Monitoring, Reporting, and Verification

1 Carbon Capture (Utilization) and Storage

Comments on the CCS Intentions Paper highlighted the absence of information regarding CO_2 utilization, noting that this omission could restrict the eligibility of pathways and facilities employing CCUS. Several submissions recommended explicitly incorporating carbon intensity (CI) reduction benefits associated with CO_2 utilization into the lifecycle assessment (LCA) modeling framework.

Further comments addressed Enhanced Oil Recovery (EOR), expressing concerns about the differential treatment of CO_2 under EOR versus CCS, the treatment of oil production not associated with EOR, and the handling of surplus oil volumes. Respondents also questioned the statement that "EOR is the most common," cautioning that this may not consistently reflect current practice. Additionally, concerns were raised regarding the separation of CCS and CCUS into distinct categories.

2 Eligibility/Criteria

2.1 Reservoir Pressure

Several comments questioned the eligibility criterion that excludes projects which reduce reservoir pressure after the completion of CO_2 injection. Respondents requested additional context on the rationale behind this requirement and noted that pressure changes are often part of natural reservoir stabilization, particularly in larger or less confined geological formations.

Stakeholders expressed concern that this criterion could disqualify technically sound projects or limit storage to only certain reservoir types. They proposed allowing some

flexibility for pressure equalization, provided that long-term storage integrity is demonstrated.

There were also requests for clarification on scenarios involving CO_2 extraction by third parties after project completion as well as guidance on whether CO_2 could be transferred between projects for economic or risk mitigation purposes without affecting eligibility.

2.2 Pre-approved Regions

Stakeholders generally supported the concept of pre-approving jurisdictions with robust regulatory oversight for CO_2 storage. Many comments encouraged the Ministry to formally recognize U.S. federal and state-level programs, especially the U.S. EPA's Class VI well regulations and states with primacy for implementing these programs, such as North Dakota.

Several respondents emphasized the need for a transparent and predictable process for designating pre-approved regions, including opportunities for public input and alignment with international standards. Some stakeholders advocated for expedited review of adjacent jurisdictions, particularly Alberta, citing its advanced CCS policies and infrastructure.

There were also calls for greater clarity regarding the criteria used to assess equivalency and the timeline for publishing a list of approved regions. Some submissions requested confirmation that projects operating under recognized regulatory frameworks, where CO_2 storage is demonstrably permanent, would be eligible without needing to duplicate MRV or permitting requirements.

2.3 Pore Space Ownership

Numerous submissions raised concerns about the requirement for "uncontested ownership" of the pore space used for CO_2 sequestration. Stakeholders noted that ownership and access models vary widely by jurisdiction. In many cases, project proponents access pore space through lease agreements, hub models or amalgamation frameworks rather than full ownership.

Commenters recommended amending the language to reflect jurisdictional equivalency, suggesting that access rights recognized by a local regulator (e.g., Alberta's carbon sequestration leases or North Dakota's amalgamated pore space regime) should be considered sufficient.

Some stakeholders emphasized that in emerging hub-based models, different entities may be responsible for capture, transport and storage. They asked that the protocol clarify that "ownership" of emissions and storage rights can be shared or contractual without disqualifying projects.

Other stakeholders called for transparency in how BC defines "uncontested ownership" and whether project developers operating under valid, government-issued licenses or rights-of-way would meet the intent of this requirement. Many emphasized the importance of flexibility to accommodate multi-entity project structures while still ensuring accountability and traceability of sequestration.

3 Project Periods

3.1 Reporting Period

One submission recommended that the reporting period requirements in the CCS protocol be aligned with those of primary regulators, particularly in jurisdictions such as the U.S. EPA and U.S. states with Class VI primacy. These programs typically require annual reports to be submitted in the third or fourth month following the end of the calendar year.

The stakeholder emphasized that such alignment would reduce administrative burden, promote consistency across jurisdictions and support efficient compliance for cross-border projects.

3.2 Stabilization Period

Several stakeholders supported the proposal for the stabilization period to begin on the date of the last injection and agreed with the requirement for annual sequestration project reports. However, there was broad concern about the financial and operational burden during this phase, especially for projects that may no longer generate revenue. Suggestions to address this include using part of the discount factor as a compliance support mechanism or implementing a reward system to cover ongoing costs.

One submission proposed extending the post-injection period from 100 years to 500 years to ensure long-term environmental integrity. Other stakeholders emphasized aligning BC's approach with established regulatory frameworks, such as the 50-year monitoring requirement under the U.S. EPA Class VI program and Alberta's closure certificate process.

Comments also highlighted the need for greater clarity on the definition of a "leak" or "reversal." Several stakeholders stressed that only CO_2 released to the atmosphere should be considered a reversal and that subsurface movement alone should not automatically trigger compliance actions. It was recommended that risk assessments for leakage be required only in cases where a release has been confirmed and shown to pose atmospheric risks.

Finally, clarification was requested on the conditions under which third-party verification of post-injection reports would be required, including clearer criteria and procedural guidance for when such oversight becomes necessary.

4 Risk Assurance

4.1 Discount Factor

Stakeholders offered a range of views on the proposed discount factor. Some appreciated the simplicity of the approach and supported its use as a mechanism to account for unintentional, unmeasurable releases of CO_2. Others suggested renaming it to terms like "insurance factor" to better reflect its intended role in risk mitigation.

Several submissions recommend tailoring the discount factor based on site-specific leakage risk assessments, arguing that each project presents unique risks and that this approach would also enable periodic re-evaluation following any reversal event. Some commenters proposed that high-integrity sites with robust monitoring and containment should be eligible for lower discount rates.

There were concerns that since unintentional losses are already captured within project emissions, the discount factor could result in double-counting. Others requested clarification on how discount factors are determined, how they differ from liability mechanisms, and under what conditions they apply.

A few comments misinterpreted the discount factor as a form of legal liability protection. Stakeholders emphasized the need for clearer guidance on its application and role. Suggestions were also made to allow flexibility in managing credits within the discounted pool, for instance, through agreements that return unused credits to fuel suppliers following the monitoring period. However, others cautioned that since the discount factor assumes those emissions have been released, such credits should not be reclaimable.

Stakeholders broadly supported alignment with risk assurance practices in other jurisdictions and emphasized the importance of transparency in the rationale, design, and implementation of the discount factor mechanism.

4.2 Double Counting

Stakeholders broadly supported the intention to prevent double counting of emissions reductions across non-stackable programs and generally agreed with the requirement for a statutory declaration. However, several submissions suggested using more flexible terminology, such as "declaration," and called for greater clarity on the scope and application of this requirement.

Many commenters asked for explicit guidance on which programs are considered stackable. Several emphasized that participation in the U.S. 45Q program and Alberta's TIER program should not preclude eligibility for BC LCFS credits, particularly where different accounting frameworks or objectives apply. Some highlighted that emission reductions reported under TIER also feed into federal inventories and may be simultaneously recognized under the CFR, raising questions about the boundaries of creditable reductions.

There was support for allowing CO_2 utilization projects to participate in multiple programs, if emissions reductions are not double-credited. Stakeholders recommended using statutory declarations or other declarations as a mechanism to confirm that emissions reductions have not been separately sold or claimed.

Comments also raised concerns about selling CO_2 into the voluntary market. It was suggested that if CO_2 is sold to a third party for use in offsetting activities, corresponding reductions should be excluded from LCFS crediting to avoid duplication.

Some commenters emphasized the importance of distinguishing between product-level carbon intensity accounting under LCFS and broader emissions reporting for national inventories or border carbon adjustments. They requested additional clarity on how the Ministry will handle participation in international programs such as CORSIA, and how participation in programs like the federal Clean Hydrogen Investment Tax Credit (CHITC) would interact with LCFS eligibility.

Several stakeholders expressed concerns about the disclosure of sensitive commercial information and recommended that declarations, rather than data submissions, be

sufficient to demonstrate compliance with double counting provisions. Others noted that Canada's Greenhouse Gas Reporting Program (GHGRP) already includes protections that could prevent double counting without the need for redundant provisions in the protocol.

Lastly, some fuel producers expressed concern about limitations on allocating CI reductions across fuel batches and selling those gallons into different LCFS markets. They noted that no policy rationale had been provided to restrict such market flexibility.

5 Project Description

5.1 Baseline Condition

Stakeholders generally supported the use of a dynamic baseline to reflect emissions under business-as-usual scenarios. Many emphasized the importance of aligning the baseline with measurable parameters and data sources to ensure consistency and comparability across projects.

Several submissions requested that the protocol include clear guidance on establishing baselines for different facility types, including existing versus new projects and varying capture configurations. Some noted the need to clarify how emissions from facilities undergoing operational changes would be treated, to avoid penalizing upgrades or efficiency improvements.

There were also calls for greater transparency on what constitutes valid baseline data and for the Ministry to provide example scenarios or templates to assist project developers. A few stakeholders noted that the baseline condition must accurately reflect emissions that would occur in the absence of a CCS project and should exclude emissions reductions from unrelated process improvements.

Some stakeholders raised questions about whether the baseline should include emissions from upstream processes or be limited to on-site sources. Others encouraged alignment with federal and international LCA frameworks to avoid inconsistencies in carbon intensity determinations.

Overall, stakeholders emphasized the need for a clear, standardized, and flexible approach that ensures environmental integrity without creating unnecessary administrative burden.

5.2 Project Entities

Stakeholders emphasized the importance of accommodating CCS project structures involving multiple entities across capture, transport, and storage. They supported recognition of distinct legal and operational roles and encouraged clear definitions of responsibilities among parties.

Several submissions recommended designating a lead reporting entity while allowing other participants to contribute relevant data through contractual or data-sharing arrangements. Commenters requested flexibility to use agreements like those accepted in other jurisdictions, such as the U.S. and Alberta.

Stakeholders also called for clarity on how project changes, such as shifts in partners or operators, would be managed under the protocol, and asked whether standard templates for agreements or declarations would be provided.

Overall, commenters stressed the need for flexibility, legal clarity, and traceable emissions accounting in multi-entity CCS projects.

6 Sources, Sinks and Reservoirs

6.1 Baseline

Stakeholders broadly supported aligning the baseline approach for Sources, Sinks, and Reservoirs (SSRs) with federal and international frameworks, such as Canada's Clean Fuel Regulations (CFR). Many emphasized the importance of consistency across regulatory regimes to ensure compatibility in LCA methodologies and avoid duplication of effort.

Several stakeholders supported limiting the SSR boundary to Scope 1 and Scope 2 emissions, consistent with CFR and other CCS protocols such as the U.S. EPA Subpart RR and the CARB CCS Permanence Protocol. They raised concerns about the inclusion of Scope 3 emissions, particularly embodied emissions such as P3, P4, and P19 categories.

A specific concern was raised regarding the inclusion of well drilling emissions. Although such emissions are addressed in ECCC quantification methods, stakeholders noted that neither the BC LCFS nor the CFR includes these infrastructure-related emissions for other fuel pathways. It was recommended that drilling emissions be excluded for reasons of

consistency, limited data availability (especially for retrofits), low materiality relative to captured CO_2, and the need to amortize such emissions over the project's operational life.

Some stakeholders requested clear definitions for SSR inclusion criteria and greater transparency on what emissions sources are considered material for the baseline.

Overall, stakeholders encouraged a pragmatic, aligned approach that maintains environmental integrity while streamlining administrative requirements for project proponents.

6.2 Dedicated Storage Project SSR

Stakeholders raised concerns that the protocol includes SSRs related to the construction of carbon capture facilities and well drilling (P3CCS), while excluding the construction materials (P1CCS). They emphasized that well drilling emissions:

- Are inconsistent with how emissions are treated in other LCFS pathways;
- Are difficult to quantify for retrofit or legacy facilities;
- Represent a relatively small portion compared to CO_2 stored; and
- Should be amortized over time, which may vary by project.

Stakeholders also noted that the protocol should clearly identify which SSRs are required and provide guidance on the inclusion or exclusion of emissions categories. There was broad support for excluding emissions that are immaterial or administratively burdensome, particularly where there is no direct impact on the CO_2 storage effectiveness.

Overall, respondents advocated for alignment with existing regulatory programs, consistency across fuel types, and a focus on emissions that materially affect carbon intensity outcomes.

7 Quantification and LCA modelling

Stakeholders provided extensive feedback on quantification methods, SSR boundaries, and lifecycle assessment (LCA) approaches.

Several respondents recommended that emissions eligible for crediting be determined using actual, measured CO_2 volumes at the capture facility, rather than calculating a delta between a theoretical baseline and measured values. They noted that this approach more

accurately reflects project performance. They also supported calculating percent sequestration using only project-specific, measured emissions values.

Many supported the inclusion of Scope 1 and Scope 2 SSRs such as:

- P6: Off-site electricity generation
- P7: Off-site heat generation (though clarification was requested regarding what qualifies as P7)
- P8: Onsite electricity generation (with some suggesting exclusion if captured by fuel consumption metrics)
- P9: Onsite fuel consumption
- P16–P18: Injection site emissions and subsurface losses

There was strong feedback opposing the inclusion of Scope 3 or embodied emissions such as P3 (construction and drilling), P4 (material production and delivery), and P19 (loss/disposal of materials). Stakeholders stressed that these emissions are inconsistent with how other pathways are treated in BC LCFS and CFR, and that infrastructure emissions should either be excluded or amortized over time. Some cautioned that applying these emissions to both CCS and EOR could result in double-counting.

Multiple stakeholders sought clarification on whether CCS activities must be co-located with fuel production facilities to qualify. Examples were provided where CO_2 is captured offsite (e.g., from ethanol or hydrogen production) and later used as a feedstock in SAF or HDRD production. Commenters asked if these types of lifecycle uses are eligible for crediting.

In terms of technical modelling, several suggestions were made:

- To allow mass-based measurements for injected CO_2, in addition to volumetric + density methods
- To permit less frequent CO_2 composition sampling (e.g., quarterly for ethanol plants with purified streams)
- To clarify sequestration equations (e.g., Equations 3, 6, 7, 13) and define reasonable default values to encourage metering
- To confirm that sequestration calculations exclude emissions from fuel or energy use (as in ethanol fermentation modelling)

Stakeholders recommended that Equation 13's variable $Q_{materials,capture}$ apply to both CCS and EOR pathways. Some also proposed adding a P23 term for CO_2 transferred or sold outside the system boundary, ensuring emissions are properly accounted for when CO_2 exits the eligible crediting system.

Concerns were raised about CO_2 being treated as a co-product, with some arguing that it lacks energy content and should not be included in energy-based CI calculations. Others pointed to the need for further guidance in cases where CCS is applied to intermediate products that later become low-carbon fuels (e.g., ethanol to jet, blue hydrogen to jet).

Finally, feedback emphasized the need to define the time used in sequestration calculations. Stakeholders preferred using monthly values tied to real-time pathway applications, consistent with recent regulatory precedents in BC, and cautioned against using annual averages or prior year data for current-year reporting.

8 Monitoring, Reporting, and Verification

Stakeholders generally supported aligning MRV requirements with local regulatory frameworks but recommended imposing minimum standards where jurisdictional oversight may be insufficient. They emphasized that MMV plans and modelling requirements should be site-specific, based on storage risk and project characteristics, rather than applying uniform requirements such as 100-year post-injection modelling on an annual basis. Clarification was requested on how the ministry would determine when additional MRV obligations apply.

Feedback also addressed the scope and burden of annual reporting during and after injection, the definition of a verified statement of permanence, and the need for clear third-party verification rules. Commenters asked for recognition of U.S. regulatory programs, acceptance of equivalent professional designations, and publication of approved verification bodies and verifier qualifications. These points are detailed in the subsections that follow.

Several submissions emphasized the importance of site-specific MMV plans, noting that risk profiles vary by geology, project type, and regional regulations. Stakeholders recommended that MRV submissions include a clear summary of the project's monitoring strategy, risk profile, and the mitigation measures in place to address those risks.

8.1 Reporting

Stakeholders raised concerns about the requirement for annual sequestration reports during and after the injection period, especially where long-term post-injection monitoring extends for decades. Some noted that submitting detailed annual reports indefinitely could be unnecessarily burdensome for low-risk sites. Others highlighted that projects with complex injection histories or limited baseline data may face additional complications during the stabilization phase.

Several respondents recommended aligning reporting requirements with those already accepted by local regulators. For example, stakeholders pointed to Alberta's Directive 065 and the Shell Quest closure plan and recommended that BC accept similar documentation in lieu of duplicative reports. Others proposed that risk assessments and computational modelling be conducted once during project permitting and updated only if there is a significant change in project design or operations.

Clarification was requested on what constitutes a "verified statement of permanence" and whether local site closure certificates, such as those issued under Alberta's closure process, would satisfy this requirement. Some stakeholders also sought clarity on how cyclic injection or CO_2 recycling activity would affect timelines and reporting obligations during the stabilization period.

Overall, stakeholders supported the need for accountability during long-term storage but emphasized the importance of proportionate, risk-based reporting expectations and coordination with existing regulatory systems.

8.2 Verification

Stakeholders requested further detail on the ministry's proposed third-party verification requirements. Several submissions sought clarity on when verification would be required, what qualifications are expected and whether existing professional designations, such as U.S.-based professional engineers and geologists, would be accepted as equivalent to Canadian P.Eng. or P.Geo. certifications.

There were calls for the ministry to publish a list of accredited verification bodies and to define minimum qualifications for both lifecycle assessment (LCA) specialists and third-party verifiers. Some noted that it was unclear whether third-party verification would be

required for all reports or only in specific situations, and recommended this be clarified through a future guidance document or intentions paper.

Stakeholders generally supported leveraging verification processes that are already embedded within regulatory programs such as the U.S. EPA's Class VI and GHGRP Subpart RR frameworks. They recommended that BC avoid duplicating verification requirements where equivalent oversight already exists and that the ministry consider accepting MRV documentation verified by a primary regulator as sufficient.

Finally, several stakeholders recommended that the ministry reconsider the requirement for annual verification of sequestration reports during the 100-year post-injection period, suggesting that verification efforts be focused on key milestones or triggered by specific risk events.

9 Additional Feedback

Some commenters expressed appreciation for the CCS Intentions Paper, noting it establishes a precedent by recognizing the atmosphere as a shared resource and allowing crediting of projects located outside the jurisdiction. They suggested that this framework could be expanded to include new pathways, such as Direct Air Capture (DAC) combined with EOR, and requested further guidance on how fuels produced using CCS in other jurisdictions, or exported from BC, would be treated under the program.

There was strong interest in expanding the protocol to allow for CCS-based carbon intensity (CI) reductions on fossil-derived base fuels, such as those produced in refineries. Stakeholders proposed that recognizing such reductions could create additional compliance pathways under the LCFS, support CleanBC targets, and attract investment in technologies that reduce the CI of diesel, gasoline, and aviation fuels.

Additional feedback suggested tightening performance thresholds, such as requiring total emissions from capture, transport, and sequestration to remain below 3% of the sequestered CO_2. Some called for extending the post-injection monitoring period from 100 to 1,000 years to reflect long-term storage goals. To ensure environmental integrity, it was also recommended that the program impose significant penalties when third-party verification reveals discrepancies between credited and actual storage, especially if the amount of CO_2 sequestered was not directly measured.

Concerns were raised about potential public liability for long-term monitoring costs. It was recommended that project proponents establish financial mechanisms, such as trust accounts or insurance policies, to ensure that adequate funds are available for long-term storage monitoring and remediation if needed. Finally, one respondent recommended expanding the BC LCFS to address other harmful pollutants in addition to carbon emissions.

10 Resources

Some government agencies recommended reviewing the following resources during the development of the final CCUS protocol to ensure alignment with existing Acts, regulations, protocols, and standards, and to avoid conflicts between regulatory frameworks.

- Carbon Capture & Storage
- Petroleum and Natural Gas Act
- Petroleum and Natural Gas Storage Reservoir Regulation
- Guide to Acquire Storage Reservoir Exploration Licenses and Storage Reservoir Licenses
- BC Energy Regulator Carbon Capture and Storage webpage
- Energy Resource Activities Act
- Carbon Dioxide Storage Application Guide
- Carbon Dioxide Subsurface Storage Summary Document
- Draft Carbon Capture and Sequestration Protocol (CCSP) for B.C. offset Protocol
- Carbon Capture and Sequestration What We Heard Report for B.C offset Protocol
- Carbon Capture and Sequestration Offset Protocol Technical Discussion Paper
- Webinar Carbon Capture & Storage 101 (BCER's YouTube channel)
- CSA Z741:12 (R2022) Geological storage of carbon dioxide

Pathway to completing the CCS Protocol

The Ministry extends its appreciation to the industry, government, non-government and other organizations for the feedback and continued engagement in the final stages of development and implementation of the CCS Protocol. The Ministry is considering all feedback received and evaluating each comment and suggestion on its own merit in finalizing the CCS protocol.