Mary D. Nichols, Chair
California Air Resources Board
1001 I Street
P.O. Box 2815
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April 23rd, 2018

Re: Proposed Amendments to the Low Carbon Fuel Standard Regulation and to the Regulation on Commercialization of Alternative Diesel Fuels: Carbon Capture and Sequestration Protocol Under the Low Carbon Fuel Standard (Appendix B)

https://www.arb.ca.gov/lispub/comm/bccommlog.php?listname=lcfs18

Dear Chair Nichols and Members of the Board:

We appreciate the opportunity to comment on the proposed Carbon Capture and Sequestration Protocol, and Specific Purpose and Rationale under the 2018 Proposed Amendments to the Low Carbon Fuel Standard Regulation and to the Regulation on Commercialization of Alternative Diesel Fuels. The undersigned represent a diverse group comprised of industrial sources of greenhouse gases (GHGs), potential CCS project developers, technology providers, academics, and environmental non-governmental organizations (ENGOs).

Carbon Capture & Storage (CCS) is a technology that could play an important role in the climate mitigation portfolio. The Fifth Assessment Report by the Intergovernmental Panel on Climate Change found that more than half of their models failed to limit global warming to 2 degrees Celsius from pre-industrial levels without CCS and that, for those that did, mitigation costs rose by 138% on average. The International Energy Agency (IEA) estimates that carbon capture could provide between 12-16% of the cumulative emissions reductions needed by 2050. CCS can be applied to power generation, but also to industrial processes including steel, cement, and fertilizer production, natural gas processing, refining, as well as biofuels production.
In 2017, the U.S. witnessed major milestones in carbon capture, with NRG Energy's Petra Nova (Texas) plant becoming America's first coal-fired power plant retrofitted with carbon capture technology and the ADM Illinois Industrial CCS Project, a commercial-scale ethanol plant retrofitted with CCS, commencing operations. Despite these successes, there are not enough carbon capture projects in the development pipeline to meet the urgent need for emissions reductions.

The California Air Resources Board's (CARB) effort to admit CCS under California's climate programs, provided adequate safeguards are met, is a critically important effort that could help in- and out-of-state projects contribute to California's climate mitigation efforts and the reduction in carbon intensity of fuels used in the state.

While the notion of injecting CO_2 underground for the purposes of climate mitigation is relatively recent, the mechanics of it are not. Nature has been doing this for millions to hundreds of millions of years, and we should expect risks from the engineered aspects of geologic storage to be somewhat similar to oil field operations that California has conducted for a century.[1]

CARB's task at reconciling these objectives is particularly challenging. For this effort to be successful, several objectives need to be met. The rules need to be consistent with, and acceptable within CARB's regulatory framework. They need to safeguard public health and the environment, and the implementation of California's climate programs. They need to assure stakeholders and the public of the integrity of the program. Finally, they need to be workable in practice so a variety of real-world projects can utilize them and further the goal of emission reductions under California's climate goals.

The proposed CCS Protocol likely represents the most comprehensive effort to date on regulating CO_2 emissions to the air from CCS projects. We thank CARB staff for its focused and hard work in this area over the past few years. We believe that, even though not simple, the proposed Protocol contains many sound elements and goes a long way towards meeting its multiple objectives. However, some key technical changes are also necessary, which we believe can be readily accommodated within the architecture of the proposed Protocol. Contingent on these changes, the undersigned anticipate supporting adoption of the final version of the Protocol.

We look forward to continuing to work with CARB on this issue in the remaining months of this process.

Respectfully submitted,

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[1] Experience in Texas is that CO_2 operations fall within the same non-compliance ranges as other types of well failures. See Porse et al. 2014.

“Storage Complex” concept should replace “Area of Review” for delineating certain project requirements

The AOR approach is derived from the Federal Underground Injection Control Class VI requirements, which are integral to the Safe Drinking Water Act and protection of groundwater from brine intrusion. Much has been learned since the promulgation of that rule. First, the risk of elevated pressure that is referred to in the Protocol as a pressure front pertains to protection of groundwater supplies. The underlying concern pertains to the risk of driving saline brine into freshwater aquifers rather than carbon dioxide leakage to the atmosphere. Imposing this requirement across all project types could unwittingly result in an unreasonably large review volume, in some cases, infinite, such as where there is natural hydrostatic pressure updip from the formation (including the the Sierra Nevada in California). Second, the pressure front itself is an outdated concept. Pressure may extend outward from an injection well, but it is incorrect to think of it as an approximate circumference of pressure extending radially from the injected CO_2 location, but better instead to conceptualize as “areas of elevated pressure”. Furthermore, in the enhanced oil recovery (EOR) context, injection wells are surrounded by production wells which generate low pressure around them. A pressure front approach therefore cannot effectively be applied to manage risk in EOR projects. <u>To remedy this, we recommend elimination of the word “front” and replace with “elevated pressure.” In concert with this change, when referring to the subsurface and 3-dimensional volume, we recommend replacement of the “Area of Review” concept and instead recommend defining the review volume using the term already defined in the Protocol, “storage complex”, meaning the volume of rock that is predicted to contain the CO_2 plume permanently.</u>

Under this recommended approach, the terms “elevated pressure” and “storage complex” would then apply to both saline brine and EOR projects. For example, within the storage complex, all subsurface permeability zones, fracture zones, faults, and legacy wells that are transmissive with potential for induced seismicity would be risks that are identified and corrective action would be taken to avoid leakage. These conditions would then be monitored to determine if the corrective action was successful, and to determine whether these features pose risks to permanence. <u>The Area of Review (the surface overlying the storage complex) should then be only used for requirements that pertain to the *surface*, or for leakage pathways that may extend vertically above the storage complex.</u> CARB should require a three-dimensional model of the storage complex with all of the risk zones highlighted, and the approach to monitoring the risk zones included. This will also ameliorate the problem with the concept of an area of review. The maximum acceptable space for the CO_2 plume to migrate should be a volume rather than an area. An example, a horizontal well drilled outside an area of review might be deviated into the storage complex volume at depth. A three-dimensional review will assess risk from all sources.

Remediation of wells in Area of Review (Storage Complex)

<u>We suggest that CARB have the option to approve staging of well remediation in cases where well records are proven to be of good quality, all required efforts have been made to locate unknown or orphan wells, and there is a high degree of confidence in the knowledge of the location and state of</u>

wells that could act as CO_2 leakage pathways. In early stages of projects only some wells will be impacted by injection. Allowing delay of preparation of wells in outlying areas is a normal practice and low risk, and allows funding and effort to focus on high risk areas proximal to the active injection wells. Well remediation staging plans should be developed in collaboration with CARB and consistent with the area of review modeling results.

Definition of plume stability

We recommend that the plume be considered "stable" when injection has ended, and the rates of CO_2 migration and changes in pressure have decreased so that the risk of CO_2 migration out of the storage complex is calculated to be minimal with a very high degree of confidence. Demonstration of stabilization should be accomplished by a combination of measurements within, as well as at the edges of, the plume, and a good match to a fluid flow model predicting long term fate of the CO_2. We also recommend that plume stability be defined explicitly in the Definitions section and not only by reference later in the document.

Confining System

Existence of a reliable geologic barrier to vertical fluid migration is essential in creating storage permanence. We recommend that CARB require demonstration that a sequence of rocks will act as a confining system with the ability to secure CO_2 permanently.

The proposed Protocol requires that "[t]he storage complex must also include at least one overlying dissipation zone (dissipation interval) and at least one additional confining layer (secondary confining layer) to increase storage security and reduce other risks."[2]

The number of layers does not imply that a site is adequate from a security standpoint. Conversely, absence of an additional confining layers does not imply that a site is inadequate from a security standpoint. There could be several circumstances where one excellent confining layer provides greater security than two layers of a lesser quality. Such is the case for the flagship Sleipner CCS project in Norway, for example.

While the requirement for a secondary confining layer and dissipation interval is potentially useful in certain parts of California, the approach has the following fundamental flaws when utilized as a general global approach:

- Rock sequences are by their very nature heterogeneous. For example, in the San Joaquin Valley, the sands are fluvial in origin which means they may be laterally discontinuous (imagine an ancient meandering river) however robust they may look in a wellbore or core sample. The requirement to present three named layers may lead to inaccurate descriptions.
- Out-of-state projects qualifying under the LCFS will likely have very different geological settings, such as carbonate sequences where a pressure dissipation interval does not exist, yet the

[2] ATTACHMENT 1: CCS Protocol – A: Definitions and Applicability, Page 20/175.

storage complex is demonstrably secure for permanent storage (e.g., reservoirs of the Permian Basin capped with salts).

- A pressure dissipation interval could be used as a primary storage reservoir given that, by definition, the interval must be overlain by a robust seal.

In addition, there appear to be conflicting definitions and requirements for the additional confining layer. The Definitions and Acronyms section[3] defines a confining layer as one that "impedes" the upward migration of fluids, whereas the Minimum Site Selection Criteria section[4] requires that the secondary confining layer be "impermeable".

<u>We recommend that CARB evaluate the potential advantages of, but not require, a secondary confining layer and dissipation interval for all projects, and instead require demonstrating that features specific to the site will reduce vertical leakage risk to acceptable levels using a geologic model and geomechanical and fluid flow data and calculations.</u>

In addition to requiring both a primary and secondary confining layer (with an intervening dissipation layer), the proposed Protocol outlines specific rock test data and formulas for characterizing the primary confinement layer. Notable among these is the determination of rock strength and ductility by means of a brittleness index calculation (BRI), with the implication that a BRI number greater than 2 may be unacceptable in that "…discontinuities may be open." Recent literature in the unconventional resources space illustrate that a such simplifications are contentious.[5] In reality, fracture containment is predominantly controlled by stress contrast between the sequestration zone and the confining layer. In areas with some degree of tectonism, "brittle" layers can be less conducive to fracture propagation, because these layers also tend to be stiffer and have a higher stress. Thus it has been concluded that "…computing shale brittleness from elastic properties may not be physically meaningful."[6]

<u>Rather than evaluating confining layers based on specific petrophysical and geomechanical properties, the quality of the entire containment system should be considered.</u> Current best practice now includes development of mechanical earth models (MEMs), which integrate the geology, material properties, pore pressure and tectonic loads to provide a more meaningful assessment of the integrity of the confinement system via prediction of stress under both pre- and post-injection conditions. This would obviate the need for secondary confining layers in some cases, and would probably increase the number of suitable storage venues (e.g., carbonates, marls, many Mesozoic and virtually all Paleozoic systems), some of which would certainly be eliminated if following the proposed criterion that is based on just a few experimentally-determined ratios.

<u>It should also be considered that the status of a seal can change from being a membrane seal to a hydraulic resistance seal, the former being considered close to impermeable and the latter permitting a very low, but constant flux of fluid across a boundary until the pressure differential is resolved.</u> The

[3] ATTACHMENT 1: CCS Protocol – A: Definitions and Applicability, Page 12/175.
[4] ATTACHMENT 1: CCS Protocol – C: Permanence, Page 44/175.
[5] Herwanger at al., 2015.
[6] Vernek, 2012.

relationships between capillary entry pressure and threshold percolation pressure in relation to reservoir overpressure need to be clearly understood in order to adequately assign levels of risk.

Strengthening the Protocol for oilfield projects

In order to better improve the security of CO_2 stored in oilfields, the design of the Protocol must take into account the inherent differences in pressure management during carbon dioxide injection for EOR projects that plan to store CO_2 rather than taking an approach that is tailored to saline projects.

<u>We recommend the following changes to improve the applicability of the rule to EOR:</u>

- Critical consideration must be given to the fact that formation pressure changes resulting from CO_2 injection are managed through production in EOR. In EOR fields, injector wells are at the center of a pattern of production wells that produce effective low-pressure zones, and therefore the concept of a pressure front is not relevant. One simple modification in the Protocol would significantly improve the efficacy of the overall approach, by changing “pressure front” to “areas of elevated pressure.”
- The Protocol should require measuring fluid flow at the correct points to obtain high quality accounting. As written, the Protocol specifies measuring injection mass just before the injection well. In EOR this measuring point will include recycled CO_2 (CO_2 produced, separated, and reinjected) along with newly supplied CO_2. This should be avoided because it results in “double counting”. Because of the possible complexity and unique surface processing during EOR, the Protocol should require the operator to identify and justify the locations and processes by which the best quality measurements can be obtained. At minimum this includes 1) the new CO_2 supplied to the project attributed to source, 2) its allocation to injection wells, and 3) an explanation of recycled fluid accounting, including any losses or releases.
- Because seal quality of a hydrocarbon reservoir is relatively well known compared to a saline formation, a best practice for EOR is to focus on analyzing past production to predict reservoir response to injection, as this will be more informative than collecting substantial additional data about the seal properties. This will require, instead, that data be collected to produce a model that can be used to define the storage complex that will accept and retain CO_2.
- A principal risk in oilfields is legacy well integrity. The Protocol as proposed requires substantial due diligence to identify existing wells in the project area, however, it should be strengthened by requiring a description of the completeness of any well databases relied upon for this analysis, as completeness may vary from state to state and field to field.
- Accounting is needed for out-of-pattern and off-lease migration. This is not new to the industry; migration can be a significant problem for EOR operators, as they may lose oil or valuable CO_2. Operators routinely use conformance metrics to track CO_2. Where CO_2 loss is a risk, water curtains (injected water blocking CO_2) and production at the boundary of a pattern or lease may be used, and discussions initiated with adjacent operators. Although the CO_2 may migrate outside the project boundary, it still may be securely stored if the adjacent operator is also recycling CO_2. Operators should report off-lease migration, and describe the estimated volumes, and methods to account for the CO_2, as well as steps taken to secure the migrated CO_2. Off-lease

migration will typically terminate when injection ceases; therefore, the use of a water curtain may be an effective mitigation strategy during injection. The use of CO_2 conformance metrics should be included in the tools recommended for monitoring CO_2 in EOR fields.

- The proposed Protocol includes well logging and core analysis that can be collected when advancing new wells. Section 2.3.1 (d) provides:
    - For a CO_2 injection well to be transitioned from a pre-existing injection, monitoring, stratigraphic test, or production well, the testing and logging information required by subsections C.2.3.1(e) through C.2.3.1(j) can be provided from previous and ongoing testing and monitoring of the formation and from well tests and logs conducted during the previous use of the well.
- Subsections C.2.3.1(e) through (j), include comprehensive well logging and core analysis requirements.
    - Existing CO_2-EOR projects may not have all the information the protocol seeks for all of its injection wells. However, a CO_2-EOR project may have acquired data during its operating history that provides equivalent or better quality information than that intended to be collected through the well logging and core analysis provisions, for example verification of the depth, thickness, porosity, permeability, lithology, and salinity of all relevant geologic formations.
    - We suggest alternative language that permits an applicant to substitute data of equivalent or better quality from other sources to verify geologic conditions.
- For existing CO_2-EOR wells and where a CO_2 injection well will be transitioned from a pre-existing injection, monitoring, stratigraphic test, or production well, data such as the testing and logging information required by subsections C.2.3.1(e) through C.2.3.1(j) can be provided from previous, proximate, ongoing testing and monitoring of the formation and from well tests and logs conducted during the previous use of the well. This should be allowed provided the data is of equivalent or better quality.

Monitoring during injection

General approach

Monitoring, in general, should be designed to detect leakage in a wide range of geologic project environments, some of which could be outside of the State of California. Monitoring plans should describe the detection process, and the effective threshold at which leakage from any possible pathway from reservoir to surface will be detected. This would include a detailed explanation (using maps and modeling) of what steps of measurement and modeling will be used to trigger a finding of leakage detection. The plan should explain in detail the process by which leakage will be verified, quantified, and mitigated, and if mitigated how the mitigation will be validated, including the accuracy and precision of the methods utilized.

Regarding the regulatory structure, we think that the Protocol would benefit from more clearly defined boundaries between the project phases. In particular, section C.4.1 should be explicitly limited to the injection phase of the project. This could be accomplished by adding the final sentence to read:

> "Testing and monitoring associated with CCS projects during the active life of the CCS project must include:[...]"

This would clearly limit the prescriptive monitoring requirements to the injection phase of the project. To the extent that monitoring is required post-injection, this is best addressed in C.5.2, Post-Injection Site Care and Site Closure.

Monitoring soil CO_2 fluxes

Baseline soil flux monitoring is a cornerstone strategy of the rule which could result in false positives or miss leakage altogether because of proven lack of broad reliability which can be confounded by natural processes. Using a baseline strategy, a monitoring technology provides a "snapshot" of the current condition and can be compared to a similar snapshot at a future date. Changes observed may be an indicator of leakage. However, soil baselines have been demonstrated to be unreliable and may lead to greater uncertainty and wasted monitoring resources.[7] Soil fluxes may vary with season, from year to year, and will undoubtedly change as climate change affects soils and natural gaseous components such as methane and carbon dioxide. Instead, a more effective approach is to require that operators propose and demonstrate the effectiveness of monitoring tools appropriate for the geologic and ecological environments within which they operate.

Our recommendation relative to soil flux monitoring is to eliminate the word "baseline", and instead establish soil concentrations to be utilized in a process-based approach rather than setting them as a snapshot of a certain period of time. Tasks may include:

- Base characterization: measure ratios of gases (N, CO_2, O_2, CH_4) in ambient atmosphere, soils, and the "Above-Zone monitoring Interval".
- Develop work plan and timeframe for collecting samples.
- Well attribution strategy.[8] Strategies should take into account soil gas trends related to climate change over the requisite monitoring period.

Monitoring of dissolved CO_2 stream

The CCS Protocol Specific Purpose and Rationale references "[t]esting and monitoring to track the extent of the dissolved and free-phase CO_2 plume and pressure front."[9] However, we are unable to find such requirements in the proposed Protocol. CARB should clarify its intent and/or rationale.

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[7] See, for example. Romanak et al., (2013): https://www.sciencedirect.com/science/article/pii/S1876610213005699, as well as our Dec 4, 2017, stakeholder feedback to ARB on the Draft CCS Accounting and Permanence Protocol and on Draft Regulatory Amendments to the Low Carbon Fuel Standard.

[8] See: presentation to CARB by K. Romanak, 2016.

[9] ATTACHMENT 2: CCS Protocol Specific Purpose and Rationale, Page 169/175.

CO_2 saturated water sinks while free phase CO_2 is buoyant. This is one of the primary mechanisms of trapping CO_2 in the subsurface, and is termed "dissolution trapping". Monitoring dissolved CO_2 is not straightforward, and could introduce additional risks by requiring the drilling of many wells to collect water samples. Given that every well impacts the environment and represents a new leakage pathway, a program that necessitates well-drilling may not generate a net environmental benefit. In addition, no geophysical methods are currently available to detect dissolved CO_2 except in low salinity situations. We recommend that an operator only be required to monitor dissolved CO_2 when the risk assessment shows that there could be some endangerment to a receptor.

Submission of tabular data

Certain provisions in the proposed Protocol require that tabular data of all measurements of a certain type be submitted on a regular basis. We support the retention of records so that essential functions such as history matching and attribution of events be possible. However, we recommend that CARB examine the feasibility and usefulness of submitting very large volumes of raw data in tabular form each applicable period. For real-time measurements on a large number of wells, this could amount to a substantial paper submission. Maintenance of appropriate records in the right format and ability by CARB to access those would be a more practical solution.

Post-Injection Site Care and Site Closure

We understand the proposed approach on post-injection monitoring to have its roots in CARB's forestry protocol. In our Dec 4, 2017, stakeholder feedback to CARB on the Draft CCS Accounting and Permanence Protocol and on Draft Regulatory Amendments to the Low Carbon Fuel Standard, we presented in great detail the fundamental differences between carbon sequestration through forestry and through CCS. We reiterate the main differences in the following table:

Characteristic	***Forestry***	***CCS***
Nature of trapping	Living organism.	Geologic, engineered.
Time frame	Typically decades or centuries. Oldest known tree was a bristlecone pine at ~4,845yrs old (very rare).	Geologic formations have trapped fluids for millions to hundreds of millions of years.[10]
Leakage mechanisms	Tree loss through felling, disease, ageing, fire, environmental factors (weather, climate).	Geologic leakage: existing faults or fractures, induced fracturing of rock. Leakage through wells.

[10] IPCC, Special Report on CCS.

Nature and magnitude of possible leakage	From trivial to catastrophic/total. Release from forest loss can be effective in returning a high percentage of the trapped CO_2 to the atmosphere.	Small for both types of leakage. With the exception of very specific settings (e.g. volcanic), which would be readily avoided, leakage through faults and fractures has been studied and shown to be very small/slow. Rate of leakage through wells is also limited,[11] and even smaller after wells have been plugged and abandoned.[12] The most severe events, surface blowouts, still produce limited leakage and are self-mitigating.[13]
Is sequestration performance predictable?	Overall, no. Fires, diseases or breaches of law/contract cannot be modeled or predicted. Health can, to a limited degree.	Yes. Sophisticated software models the CO_2 plume and is continually updated with observation data from operations. Well leakage over the course of many decades has been shown to be an occurrence, but it is limited to a very small percentage of wells, and is small in volume and correctable.[14,15,16,17]

[11] Hovorka, 2009. A production test months after the end of injection was unable to produce significant CO_2, demonstrating that it was effectively trapped because saturation had decreased to near-residual and relative permeability to CO_2 was near zero.
[12] See Mordick, B., Peridas, G., 2017, Ch.7.
[13] Lindberg et al., 2016. For the case of a surface well blowout that vented for 112 days, the authors state that "While 2.8 % of the stored gas was lost at the Aliso Canyon leak, the corresponding loss from a CO2 well if the facility was used for CO2 storage would be 0.37%. Due to the high density of CO2, the well pressure at the rupture was less than half than for CO2 compared to gas, which will make remediation easier." This represents an event that is very unlikely, and severe in its magnitude and duration.
[14] Celia et al., 2011.
[15] Kang et al., 2014.
[16] Porse et al, 2014 assess the risk to be on the order of 10^{-3}, with the relevant sample space being Railroad Commission districts in Texas. Others assess the risk to be two orders of magnitude lower (10^{-5}) based on offshore wells in the UK, highlighting that location and regulation can play an important part in mitigating risks. See, for example, HSE, 2008 (RR671) and HSE, 2008 (RR605).
[17] Pawar et al., 2009.

Is leakage preventable?	Only to some degree. Even if the land is successfully set aside and guarded, natural causes may still cause leakage (loss of trees).	Almost entirely. The entire premise of a CCS project is to select, operate and decommission a site with the goal of minimizing risk. Regulations have been found to be one of the primary determinants of the likelihood of well leakage.[18] The Permanence Protocol imposes very specific requirements in order to achieve this.
How does the risk of leakage evolve over time?	Hard to predict. Human, climatic and other factors may increase or decrease risk. No default trend, but some reason for concern (land use change, climate change).	Geologic trapping mechanisms (dissolution trapping, residual trapping and mineralization) are magnified over time. Creep and slough tend to collapse wellbores and exhibit self-healing properties. These factors combine to create an ever-decreasing risk profile.

CARB states the following:[19]

> "Based on IPCC guidance, [30] CARB has chosen 100 years[31] as the standard for the permanent reduction of CO_2 from sequestration projects under CARB's existing Cap and-Trade program. This means that any GHG emission reductions achieved from sequestration must be monitored and verified as sequestered for at least 100 years in order to be considered permanent emission avoidance and to be evaluated appropriately relative to avoiding emissions that will have a climate forcing impact calculated on a 100 year timescale. This time frame is based on the carbon cycle model used to determine global warming potentials."
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> [30] http://www.ipcc.ch/ipccreports/sres/land_use/index.php?idp=74
> [31] CARB also successfully defended this standard in court."

We do not question the efficacy of keeping CO_2 sequestered for 100 years under the proposed Protocol. We are confident that the very high degree of diligence imposed for selecting and operating sites appropriately will result in performance that far exceeds this standard. Along these lines, and

[18] Bachu & Watson, 2007 (presentation) and SPE paper.
[19] ATTACHMENT 2: CCS Protocol Specific Purpose and Rationale, Page 170/175.

synthesizing the best available technical information, the IPCC concluded in its Special Report on Carbon Dioxide Capture and Storage that:

> "based on observations and analysis of current CO_2 storage sites, natural systems, engineering systems and models, the fraction retained in appropriately selected and managed reservoirs is very likely to exceed 99% over 100 years, and is likely to exceed 99% over 1000 years. Similar fractions retained are likely for even longer periods of time, as the risk of leakage is expected to decrease over time as other mechanisms provide additional trapping."
>
> ['Very likely' is a probability of 90 to 99%]"[20]

The IPCC Guidance that CARB cites is focused on land use, land use change and forestry, and does not address the question of how long a sequestration site needs to be monitored in order to successfully demonstrate that the injected CO_2 will remain sequestered for at least 100 years. IPCC's comprehensive treatise on CCS (Special Report on CCS) also did not provide a definitive answer but that the duration of the monitoring needs to match the intended duration of the sequestration:

> "[...] The purpose of long-term monitoring is to identify movement of CO_2 that may lead to releases that could impact long-term storage security and safety, as well as trigger the need for remedial action. Long-term monitoring can be accomplished with the same suite of monitoring technologies used during the injection phase. However, at the present time, there are no established protocols for the kind of monitoring that will be required, by whom, for how long and with what purpose. Geological storage of CO_2 may persist over many millions of years. [...]
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> Until long-term monitoring requirements are established (Stenhouse et al., 2005), it is not possible to evaluate which technology or combination of technologies for monitoring will be needed or desired. However, today's technology could be deployed to continue monitoring the location of the CO_2 plume over very long time periods with sufficient accuracy to assess the risk of the plume intersecting potential pathways, natural or human, out of the storage site into overlying zones. If CO_2 escapes from the primary storage reservoir with no prospect of remedial action to prevent leakage, technologies are available to monitor the consequent environmental impact on groundwater, soils, ecosystems and the atmosphere."

Since the time of writing of the IPCC Special Report on CCS (2005), different jurisdictions have adopted different approaches to long-term monitoring.

- The operator of the Gorgon Carbon Dioxide Injection Project can apply for site closure at some point after injection operations have ceased. The timeline for this is not specified but is based on the objective of the operator demonstrating the site is performing as expected and any residual risks are acceptably low and managed. At least 15 years following site closure, the site operator

[20] IPCC, Special Report on CCS, Technical Summary.

may apply for indemnity against certain third-party claims for loss or damage that might arise as a consequence of the injection operations in the longer term.

- The Quest Carbon Capture and Storage Project will be performing 10 years of post-injection monitoring. This was determined at the outset of injection based on reservoir modeling and site-specific risk assessment.
- Peterhead/Goldeneye had a performance-based period which could be six years or longer, based on surveys demonstrating containment of the stored CO_2 and no irregularities.
- The FutureGen project in Illinois accepted the 50-year default period in its USEPA Class VI permit.
- USEPA approved a modification of the default 50-year period to 10 years for the ADM Industrial Project in Illinois. This was done based on computational modeling to delineate the Area of Review; predictions of plume migration, pressure decline, and CO_2 trapping; site-specific geology; well construction; and the distance between the injection zone and the nearest Underground Sources of Drinking Water.
- The Occidental Petroleum operated Denver Unit and Hobbs Unit in the Permian Basin (Texas and New Mexico) are establishing the long-term containment of CO_2 in the San Andres formation, with a Specified Period of 10 years at the Denver Unit. At the conclusion of the Specified Period(s), Occidental Petroleum will submit a request for discontinuation of reporting when they can provide a demonstration that current monitoring and models show that the cumulative mass of CO_2 reported as sequestered during the Specified Period(s) are not expected to migrate in the future in a manner likely to result in surface leakage. It is expected that it will be possible to make this demonstration within 2-3 years after injection for the Specified Period(s) ceases and will be based upon predictive modeling supported by monitoring data.
- Under the American Carbon Registry's Methodology for Greenhouse Gas Emission Reductions from Carbon Capture and Storage Projects, the minimum post-injection monitoring period for CCS projects is set at 5 years. The duration of post-injection monitoring is to be extended beyond 5 years if no leakage cannot be assured at the end of the 5-year period. In this case, the Project Term is to be extended in two year increments and monitoring continued until no leakage is assured. The absence of atmospheric leakage is considered assured when it can be verified that no migration of injected CO_2 is detected across the boundaries of the storage volume and the modeled failure scenarios all indicate that the CO_2 will remain contained within the storage volume.

In addition, the most current best practices literature uniformly points to a site-specific evaluation of the best methods to use in each case, taking into account variability in geology and other factors. Given the heavy emphasis on good site selection, risk mitigation and leakage prevention that underpins the entire Protocol, we believe that CARB's approach to post-injection monitoring should be modified for a number of reasons.

Given that projects will first need to be planned, financed, sited and operated, it will likely be several decades before any post-injection monitoring takes place. By that time, technology and practices are certain to have evolved beyond what is known or predictable today. The current approach locks in technologies and requirements that will lead to lower confidence, quality and environmental certainty than a tailored approach that is devised at the time when injection stops. Thus, we do not consider the proposed post-injection monitoring requirements necessarily to be conservative or environmentally protective.

We also note the added risk of any private entity defaulting on requirements that span a 100-year period. A preventative and protective approach should preempt such defaults, gaps in duty or enforcement actions by placing emphasis on proving with a higher degree of confidence earlier on that the sequestration performance will be achieved, and setting emergency funds aside for what we expect to be the rare cases when it is not.

Potential project developers also note the inherent difficulties in pursuing projects that carry with them ongoing duties that span an entire century, as well as liabilities tied to LCFS credit value that persist unless these duties are completed (we comment further on the latter below).

CARB should allow for a possible reevaluation of post-closure monitoring requirements, including but not limited to duration and methods used, once injection is complete. This will not only be done with the benefit of the extensive site data that have been collected during the injection phase, but will also make possible an assessment of remaining risk and needs on the basis of the technology and techniques of the time - not that of several decades prior. This will contribute further to sequestration integrity and performance, reducing the risk of any leakage even further.

The protocol as proposed is already structured in an appropriate manner to enable revision of the original Post-Injection Site Care and Site Closure Plan after injection has ceased. This is mandated by C.5.2(a)(3). Recognizing that the Executive Officer will retain full authority and oversight over the scope of the monitoring at this time, we recommend that mandatory provisions contained in C.5.2(a) and C.5.2(b) be more limited. While all of these monitoring tools should be available for the Executive Officer to impose based on site conditions and experience, the current list is more limiting than is warranted for every project. We are certain that the state of sequestration science, and the best available technologies and best practices will expand in the coming decades. Prescribing tools now is worse both from an environmental and a project development and operation standpoint. We therefore recommend that CARB not build in mandatory regulatory language except to the extent necessary. An appendix below contains a redline with our specific suggestions in this area.

Regarding the default provisions as currently proposed that would apply prior to a revision of post-closure monitoring requirements once injection is complete, we make the following recommendations:

- As we explain at length in our Dec 4, 2017, stakeholder feedback to CARB on the Draft CCS Accounting and Permanence Protocol and on Draft Regulatory Amendments to the Low Carbon Fuel Standard, soil gas monitoring is already known to suffer from inherent limitations. If the post-injection monitoring section is to continue to prescribe types of method, the reference to soil gas[21] should be changed to "near surface" monitoring, to allow for other, more effective, techniques that could detect CO_2 in the shallow subsurface. This is further detailed above.

- Similarly, the requirement to perform visual wellhead checks[22] should be revised to allow for more effective alternatives such as automated methods or remote sensing to confirm wellhead integrity and detect any leaks there.

Invalidation of credits and Time-Adjusted Warming Potential

Some provisions in the proposed Protocol contemplate an invalidation of *all* credits generated upon specific occurrences, or do not rule out such a possibility. For example:

- If a well loses mechanical integrity and injection does not immediately cease.[23]
- Section C.7.3, which states that " financial responsibility instrument(s) must be sufficient to address the potential endangerment of public health and the environment via atmospheric leakage."

Such an approach does not recognize the accrued benefits to the atmosphere from preventing a CO_2 emission in the first place and keeping it sequestered for a certain period of time, and goes against CARB's own stated justification for using a 100-year period as the definition for permanence, which identifies a partial atmospheric benefit over shorter periods as well.[24]

In cases where CO_2 has been verified to have remained sequestered for a given period in accordance to the requirements set forth in the Protocol (i.e. absent any error, fraud or other occurrence of non-compliance that was not dealt with according to the provisions of the Protocol), CARB should recognize the atmospheric benefit of sequestration periods shorter than 100 years by applying an up-to-date calculation.

For example, as a current best practice, a time-adjusted warming potential[25] can be calculated for a project that injects $1MtCO_2$/yr for 30 years and (1) retains all injected CO_2 permanently or (2) emits the entirety of the injected CO_2 70 years after after injection begins.[26] In the former case of no release, the time-corrected CO_2e would be -26.6Mt over an analytical time horizon of 100 years. In the latter case of the total release, the time-corrected CO_2e over a 100-year analytical time horizon would be -14.9Mt. Hence, with a total release at 70yrs, the emissions/credit liability for the project should be capped at the difference of the two, i.e. $11.7MtCO_2e$. Such a release scenario is not possible, but we present it for illustrative purposes.

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[21] ATTACHMENT 1: CCS Protocol – C: Permanence, Page 102/175.
[22] ATTACHMENT 1: CCS Protocol – C: Permanence, Page 103/175.
[23] ATTACHMENT 1: CCS Protocol – C: Permanence, Page 77/175.
[24] Reference to IPCC guidance, ATTACHMENT 2: CCS Protocol Specific Purpose and Rationale, Page 170/175.
[25] As described by Kendall, 2012, and using the author's provided calculator.
[26] Entering -1 in the calculator for years 0-29, and then entering either 0 or 30 for year 70.

Financial Responsibility

We perceive significant opportunities to introduce additional flexibility to the financial responsibility section without undermining CARB's authority to ensure that there are sufficient underlying assets to support project obligations and address risks. Section C.7(a)(3) appears open to varying interpretations.

Based on our review of other references to atmospheric leakage in the protocol, we think that this section should be revised to state, "The financial responsibility instrument(s) must be sufficient to address the risk of atmospheric leakage of CO_2." We also think that post-injection financial responsibility under C.7(a)(3) should be reduced by contributions to the buffer pool during the CCS project's active life. This is further explained below.

Out-of-state storage projects

CARB's protocol, as written, establishes identical requirements for CCS operations that take place outside of California as in state. While we support rules that establish a common outcome - the secure long-term storage of CO_2 - regardless of location, regulatory requirements in out-of-state jurisdiction may not allow for identical practices.

For example, would ARB require post-closure monitoring beyond the duration allowed by another local government? Would operators always be required to follow a different monitoring program than that which may already be locally mandated and enforceable elsewhere? Would ARB impose different bonding requirements on these out-of-state projects? Would the Protocol mandate different well maintenance activities, changes to operating procedures, or approval of site selection that may conflict with requirements that are subject to local regulation and approval elsewhere? In some, or likely many, cases, specific requirements in California's Protocols will have an analogue in another local jurisdiction, each with the intent of ensuring safe, permanent storage of CO_2. In other cases, they may not have an analogue, or they may not be as stringent as California's requirements.

ARB should follow an approach that allows for functional equivalence to be the criterion by which the sufficiency of requirements from other jurisdictions are evaluated. Specifically, we recommend that the Protocol, through a new (sub)section, provide the Executive Officer with the option to accept certain requirements, data sources, methods or techniques from other jurisdictions in lieu of any relevant specific requirements in the Protocol, provided these offer an equivalent or better level of assurance in permanence than the requirements in the Protocol, and provided there is a demonstrated conflict between CARB's requirements and those of the other jurisdiction.

We want to emphasize that we are not advocating for more lenient or favorable treatment for projects in other jurisdictions. We simply want to ensure that projects also governed by other requirements, or that use practices that are equivalent or better than those that would qualify under the Protocol, are not excluded from eligibility due to inconsequential mismatches in those requirements or practices.

Leakage assumption and detection limits

The proposed Protocol defines injected CO_2 to have leaked at the rate of half the sensitivity of the equipment employed to detect leaks.

Absent an indication from the monitoring program or otherwise, none of the injected CO_2 can justifiably be deemed to have escaped to atmosphere. The entire premise of the Permanence Protocol is to prevent any leakage. This is achieved through several layers of design and operational practices. For CO_2 to be leaking at levels that are below any given detection limit, all of those lines of defense need to have failed: a leakage pathway is required along with sufficient time for the CO_2 to reach the surface. Although this is possible, we consider it highly unlikely in practice, and see the de facto presumption of leakage under the detection threshold as undermining CARB's faith in its own regulations. The proposed provision effectively assigns a probability of 1 to leakage.

Moreover, despite all those lines of defense, CARB is proposing to collect Buffer Account contributions in order to take into account possible reversals – an approach that we support. Assuming a default rate of leakage is duplicative from a standpoint of incorporating conservatism into the accounting.

Finally, while we recognize that there is an inherent degree of imprecision in the flowmeters at the wellhead, these devices are routinely checked, calibrated and accepted for use in both commercial and regulatory applications. Any imprecisions may just as likely undercount as to overcount the quantity flowing through them.

<u>For these reasons, CARB should not reduce the quantity of credits issued due to detection thresholds on the basis of conservatism. If a default rate of leakage is to be assumed on the basis of detection limits, CARB should make a determination not necessarily on the basis of equipment, but by considering the leak detection "methods" employed.</u>

Well integrity

The protocol currently defines well integrity as a binary system under which legacy wells need or do not need corrective action. We recommend a three class system to account for more timely interventions. The recommended assessment system would include determination of:

- Wells assessed to be effectively sealed (by plugs or natural closure)
- Wells that require intervention, and
- Wells that will be monitored to ensure that they maintain integrity; if not, they will be replugged. This assessment would account for the current extent of the pressure and CO_2 plume and imply a rolling program of well work as the usage of the store expands.

The inclusion of the third class allows the operator to avoid reopening wells that have been sealed by natural mechanisms such as shale creep, thereby minimising environmental impact of well operations and reducing the risk of leakage through the reopening of wells. The requirement for monitoring maintains the security of the store.

Section C.4.2(b)(2) states that wells must be tested for mechanical integrity at least once each year, or on a testing schedule approved by the Executive Officer. We suggest the option of aligning the testing schedule with regulatory bodies overseeing mechanical integrity testing in other jurisdictions to prevent redundancy and overlapping authority, provided this does not result in a dilution of confidence in mechanical integrity and storage security.

Metering

Metering is currently required at the wellhead.[27] We recommend that CARB allow for central metering and allocation at the storage site to individual wells provided it can be shown that data obtained using this method is no less accurate, available or reliable.

Seismic evaluation

Section C.3.2.3(e) provides: "The results of the seismic evaluation must be reported to the Executive Officer within 30 days following the earthquake". In cases where access to the site following such a seismic event is limited, we recommend that CARB allow for preliminary results to be supplied within 30 days, and final results within 120 days. Even under normal circumstances, 30 days may not be sufficient time to complete the analysis. Processing and interpretation of seismic data is a time consuming activity requiring many hours of time on large computing clusters and multiple iterations.

Simulation

We suggest that the Protocol allow for use of commercial codes as long as these are shown to be sufficient by comparison with open source code. Commercial codes can under some conditions provide better and faster numerical solutions. In some cases, updated codes may only be available commercially.This has been evident in situations involving complex miscible fluids. Transparency should be provided by providing complete documentation of the model inputs, calibration, and workflow.

Description of "all" geologic structures

The proposed Protocol requires "[a] full description of all geologic structures, including faults and fractures, which intersect the storage complex and all data relevant to assessing the transmissivity of these features". Faults and fractures can vary from very large to micro-scale, and a strict interpretation of this provision renders the task impossible. We recommend that the Protocol require the project operator to describe such features which affect leakage risk, along with a justification of the scope of the description.

Water wells

The proposed Protocol requires that all water wells are listed, described and located. In some jurisdictions, private drilling of shallow groundwater wells may be unregulated. State- or

[27] ATTACHMENT 1: CCS Protocol – C: Permanence, Page 80/175.

county-maintained records of existing wells may also not exist. CARB should consider the requirement against this background, consulting with the State Water Resources Control Board and the Department of Water Resources in California, and also consider out-of-state jurisdictions.

Buffer Account contributions

We understand CARB's need to set Buffer Account contributions conservatively at first, before a broad experience with CCS projects is in place. At the same time, in order to deploy successful CCS projects, potential investors need to be able to reasonably predict project returns. Table G1 in Appendix G is a good start to helping industry understand how projects returns will be affected by Buffer Account contributions.

However, not all projects will be able to fit into predefined risk categories absolutely. For example, under the "Financial" risk type, Table G.1 suggests that project participants are of low risk if they have "A" credit ratings. However, credit ratings are only acquired by entities that have debt. Since CCS deployment is still in its early stages, potential early projects could be funded purely through private equity. These newly formed private equity firms could be more financially stable then an A rated company simply because they have access to large funds. Projects that are well-funded by private equity should not be relegated to a higher risk profile simply because they have no need to borrow funds for a project. We suggest, therefore, that the Executive Officer have the ability to review cases in which a credit rating is not available and determine the appropriate risk level with the project entity.

Under the "Well Integrity" risk type, CARB has predefined Low Risk and High Risk by segregating them as Class II and Class VI respectively. Though a well may be permitted under Class II, it may have been designed and constructed to standards beyond the minimum requirements of a Class II well. In fact, some operators have disclosed that they exceed Class II requirements of their own accord.[28] The Executive Officer should examine the actual well integrity risk for a project's wells as opposed to relying on their regulatory class under USEPA (UIC) only, and assign a risk rating accordingly. It is not clear whether the intent of Table G.1 under this risk type is to examine the actual regulatory classification under USEPA (UIC) only, or the actual standard of the wells.

In addition, other risk categories may not fall into the predefined risk profiles setup in Table G.1. We recommend that the Executive Officer have the option to modify or update the risk rating contribution up or down within the bounds set in Table G.1 for a project based on information on technology and practices provided by the prospective project operator.

In addition to these concerns relating to the Table G1 contained in Appendix G that effectively establishes a minimum risk floor rating for all projects, we think there are additional opportunities to clarify the methodology of risk assessment and utilize the credits that CCS projects have deposited into the buffer account to lessen the burden of unnecessary long-term financial exposure the protocol now creates. Specifically, we advocate three additions to the rule:

[28] See Mordick, B., Peridas, G., 2017, Ch.5.

1. The utilization of the risk calculation methodology contained in Appendix G not just to determine the amount of mandatory credit contributions to the buffer pool but also to assign the level of financial responsibility instruments that are required by C.7.(a)(3).
2. The establishment of a new table in Appendix G that contains a different risk matrix for the post-injection phase of projects. We think that by this stage in a project's lifespan, most projects will have a sufficient history to establish the risk of atmospheric leakage with far greater accuracy and certainty, and that the table should contain appropriate risk values that enable this for qualifying projects.
3. Since a project will have contributed a substantial number of credits to the buffer pool during its lifespan, we think that the project's specific contributions should be available to use as a financial responsibility instrument to cover future leakage risk.

Permanence Certification

Transferability

Section C.1.2(b) provides:

"The Permanence Certification is non-transferable."

We are not clear on the rationale behind this provision. We can envision a situation where it both be preferable from an environmental standpoint to transfer a project to a more competent and/or financially sound operator, and commercial situations where an operator may wish to transfer a project to a new owner. <u>CARB should explain the rationale behind this provision. If transfers are to be allowed, subsequent CCS Project Operators should demonstrate that they meet the requirements of the Protocol.</u>

Inactivity

Section C.1.2(c) provides:

"Permanence Certification must expire, and be deemed null and void, upon the first day following 24 consecutive months of no injection at the GSC project, and a new approval process and re-certification would be required prior to restarting injection."

This is an unnecessary restriction on a CCS Project's operational parameters. There is significant uncertainty as to the consistency that the LCFS market might have in the early years of development. Having made the investment to obtain a Permanence Certification, a project operator may find that the infrastructure to insure reliable supplies of CO_2 for a project is not yet fully operational or may be subject to periodic disruptions. It is possible that some disruptions may require a significant investment and time to cure (e.g., a pipeline may need to be constructed that will require obtaining multiple right or ways that could require significant time to obtain).

<u>We recommend that an operator be allowed to suspend injection following a submittal to, and subsequent approval by CARB. Once reliable supplies of CO_2 were restored, and assuming the operator</u>

has maintained all other aspects of the CCS Project in accordance with the application, injection should be permitted to resume.

We offer the following proposed alternative language:

> "1.2(c) Prior to entering post closure, in the event injection is suspended at the CCS Project, an operator may apply for a temporary suspension of its Permanence Certification. The operator shall continue to comply with the monitoring, reporting and verification requirements of this protocol and its application at all times during the suspension. Before restarting injection, the operator shall provide the Executive Officer with ten days advance notice."

Accounting

In section B.2.2(d), the text states:

"Annual GHG emissions from CO_2 transport must be calculated using Equation 4. CO_{2vent} and $CO_{2fugitive}$ in Equation 4 are zero if the CO_2 is of biogenic origin, such as from sugar fermentation, or derived from direct air capture."

However, the terms CO_{2vent} and $CO_{2fugitive}$ do not appear in Equation 4. Rather the terms appear in Equation 5. This should be corrected.

Mitigation Plan

In Table 2, a Mitigation Plan is required to address substantial and catastrophic risks that are possible and catastrophic risks that are unlikely. This is the only place in the document where the phrase "Mitigation Plan" appears. CARB should clarify if it is receptive to the use of best management practices, or refer to established guidance.

Unintentional CO_2 leakage

Section B.3(d)(1), provides:

"All CCS projects must contribute a percentage of LCFS credits to the Buffer Account at the time of LCFS credit issuance by CARB. The CCS project's contribution to the Buffer Account is determined by a project-specific risk rating method, outlined in Appendix G. If CO_2 leakage unintentionally occurs at a CCS project, LCFS credits from the Buffer Account will be retired according to the provisions for invalidation in the LCFS."

In the course of continuous operations, CCS Projects may have unintentional CO_2 leakage from various sources. This leakage is accounted for under section C.2.2 and no LCFS credits generated for CO_2 that is not sequestered: fugitive or emissions from the subsurface to the atmosphere are reported under their own terms and no credits are issued for those quantities. The above language creates some ambiguity as to when and under what circumstances LCFS credits should be invalidated. Presumably, LCFS credits may be invalidated only where the CO_2 leakage exceeds the CO_2 sequestered in a given reporting period.

We offer the following proposed alternative language:

> "All CCS projects must contribute a percentage of LCFS credits to the Buffer Account at the time of LCFS credit issuance by CARB. The CCS project's contribution to the Buffer Account is determined by a project-specific risk rating method, outlined in Appendix G.
>
> If CO_2 leakage unintentionally occurs at a CCS project, and the leakage exceeds the quantity of CO_2 stored by a CCS Project in a given reporting period, LCFS credits from the Buffer Account will be retired according to the provisions for invalidation in the LCFS."

We further clarify that the suggested language is not intended in any way to interfere with operational requirements (relating to the cessation of injection or otherwise) for wells where leakage is detected or loss of mechanical integrity suspected.

Well plugging and abandonment

Section 5.1 requires a well plugging and abandonment plan be developed and submitted with the Sequestration Site Certification. The plan must be updated as needed throughout the life of the project. We agree that ensuring wells are properly plugged and abandoned is an important component of the protocol and will help ensure the long term integrity of the CCS Project. The demonstration, however, should not require a detailed plugging and abandonment plan since changing technology and conditions may well render any plan prepared 100 years or more before closure, obsolete. Rather, the protocol should ensure that the project operator at the time of closure develop a detailed plan compliant with the best management practices, technologies and materials of that time, provided these are better than at the time of project certification, or require a performance standard to be met.

Variations in the composition of CO_2 stream

Section 1.1.3.4(b) states that an analysis of any changes to the composition of the injection fluid must be submitted to the EO for review and written approval at least 30 days prior to injection. CARB should clarify what constitutes "changes to the composition" as CO_2 percentages may vary in the course of operations. Additionally, WAG injection via CO_2-EOR may have water alternating with CO_2. CARB should clarify whether the water injection cycle is included in the definition of Injection Fluid, which is not defined.

Use of public records for assessing well integrity

Section C.2.4.3(c) states that "CCS Project Operators must perform corrective action on all wells within the AOR that are deemed to need corrective action, including all wells that penetrate the storage complex and are determined to have been plugged and abandoned in a manner such that they could serve as a conduit for fluid movement into the shallower subsurface, prior to the commencement of injection." Furthermore, Figure 6 displays a flow chart. One box states "Do records indicate the wells are plugged in a manner that will prevent carbon dioxide plume of formation fluid migration…"

<u>CARB should clarify to what extent existing records can be relied upon at state and federal regulatory levels in determining the basis for corrective action. We note that the quality and reliability of records varies.</u>

Invalidation of credits and cessation of injection

> Section C.3.3(f)(1) states that all credits generated are subject to invalidation if injection does not cease immediately if a well shows indications of mechanical integrity issues. CARB should clarify whether this applies to ceasing injection at that well or across the entire CCS Project. <u>Given the scale of potential CCS Project operations, we suggest it apply to ceasing injection at the well. This would also be consistent with Section C.3.4(a). Secondly, CARB should clarify what the period of credit invalidation is.</u>

Contracts restricting activities

Section C.9(c) requires the CCS Project Operator to show proof that there is a binding agreement among relevant parties that drilling or extraction that penetrate the confining layer above the sequestration zone are prohibited within the AOR to ensure public safety and permanence of stored CO_2. It is critical that there be controls in place to safeguard against a party penetrating the confining layer or sequestration zone in such a manner that there is a risk that stored CO_2 is released. However, a contractual agreement is only one tool to safeguard against such an event. In some states there are existing regulatory requirements (e.g., in Texas, rules by the Department of Licensing and Regulation), that prescribe how wells are to be advanced to avoid uncontrolled releases from the subsurface or mixing of fluids from different zones. In some cases, these regulatory requirements may be superior to a contractual agreement because of the involvement of the state regulatory authority. The Protocol should give the Executive Officer the option to accept such requirements if an operator demonstrates that existing regulatory obligations provide at least the same level of protection as may be afforded by a contractual agreement. We suggest the following revision to Section C.9(c):

> "The CCS Project Operator must show proof that there is <u>a regulatory obligation or</u> a binding agreement among relevant parties that drilling or extraction that penetrate the confining layer above the sequestration zone are prohibited within the AOR to ensure public safety and the permanence of stored CO_2".

Miscellaneous

Definitions (80): "Net working capitol" should be "Net working capital".

Page footer: "CCS Protocol Specific Purpose and Rational" should be "Rationale".

APPENDIX: Redline pertaining to specific revisions in the proposed Protocol as referenced above in our comments:

APPENDIX B – ATTACHMENT 1:
CARBON CAPTURE AND SEQUESTRATION PROTOCOL UNDER THE LOW CARBON FUEL STANDARD

[...]

B. ACCOUNTING REQUIREMENTS FOR CCS PROJECTS UNDER THE LCFS

[...]

3. Invalidation and Buffer Account

(a) Verified GHG emission reductions associated with CCS projects will be invalidated if the sequestered CO_2 associated with them is released to the atmosphere or other unauthorized zone.

(b) The amount of verified GHG emission reduction to be invalidated for CCS projects is equal to the CO_2 leakage from the storage complex ($CO_{2leakage}$), which must be determined in accordance with subsection C.4.3.2 of the CCS Protocol.

(c) A Buffer Account maintained by CARB pursuant to the LCFS provides insurance against invalidation of GHG emission reduction credit due to CO_2 leakage.

(d) Provisions for invalidation of GHG emission reduction credit are set forth in the LCFS.

(1) All CCS projects must contribute a percentage of LCFS credits to the Buffer Account at the time of LCFS credit issuance by CARB. The CCS project's contribution to the Buffer Account is determined by a project-specific risk rating method, outlined in Appendix G. If CO_2 leakage unintentionally occurs at a CCS project, LCFS credits from the Buffer Account will be retired according to the provisions for invalidation in the LCFS.

(e) <u>The buffer account balance of a CCS project is based on the CCS project's total contributions of credits to the buffer account made by the project during the period of injection reduced by any leakage from the project's storage complex pursuant to B.3(b).</u>

(f) <u>After injection has terminated and the CCS Project Operator has either received approval for an amended Post-Injection Site Care, and Site Closure Plan or demonstrated to the Executive Officer through monitoring data and modeling results that no amendment to the plan is needed, the Project Operator may use the project's</u>

buffer account balance as a qualifying financial responsibility instrument. The buffer account balance may only be used to satisfy the risk of atmospheric leakage of CO_2 as further described by C.7(a)(3). The CCS project's buffer account balance does not have any other purpose or value.

[...]

C. PERMANENCE REQUIREMENTS FOR GEOLOGIC SEQUESTRATION

1. Permanence Certification of Geologic Carbon Sequestration Projects

[...]

1.2. Terms and Conditions

(a) Any changes to the operational parameters of a Permanence Certification are subject to approval by the Executive Officer and must be noted in either an addendum to the ~~a~~ Permanence Certification or a revised Permanence Certification.

(b) The Permanence Certification is ~~non~~-transferable subject to approval by the Executive Officer that must be noted in a revised Permanence Certification.

(c) Permanence Certification must expire, and be deemed null and void, upon the first day following 24 consecutive months of no injection at the GSC project, and a new approval process and re-certification would be required prior to restarting injection.

[...]

4. Injection Period Monitoring Requirements

4.1. Testing and Monitoring

(a) Testing and Monitoring Plan. The CCS Project Operator must prepare, maintain, and comply with a testing and monitoring plan to ensure that the CCS project is operating as certified and that the CO_2 injected is permanently sequestered. The Testing and Monitoring Plan must be submitted with the application for Sequestration Site Certification, and must include a description of how the CCS Project Operator will meet the testing and monitoring requirements, including accessing sites for all necessary monitoring and testing during the active life of the CCS project and the post-injection site care period. Testing and monitoring associated with CCS projects during the active life of the CCS project must include:

(1) Analysis of the CO_2 stream with sufficient frequency to yield data

representative of its chemical and physical characteristics pursuant to subsection C.4.3.1.1;

(2) *Installation and use, except during well workovers, of continuous recording devices to monitor: (1) injection rate and volume pursuant to subsection C.4.3.1.2, (2) injection pressure and the pressure on the annulus between the tubing and the long string casing pursuant to subsection C.4.3.1.3, and (3) the annulus fluid volume added;*

(3) *Corrosion monitoring of well materials, upon well completion and a minimum of once per every five years thereafter, for loss of mass, thickness, cracking, pitting, and other signs of corrosion, to ensure that well components meet the minimum standards for material strength and performance set by API, ASTM International, or equivalent, by:*

(A) *Analyzing corrosion coupons of the well construction materials placed in contact with the CO_2 stream; or*

(B) *Routing the CO_2 stream through a loop constructed with the material used in the well and inspecting materials in the loop;*

(C) *Performing casing inspection logs; or*

(D) *Using an alternative method approved by the Executive Officer.*

(4) *Periodic monitoring of pressure and/or composition above the storage complex. In sites where it is feasible and useful, groundwater quality and geochemistry must be considered. The rationale and leakage detection threshold of the selected monitoring method must be demonstrated;*

(5) *The location and number of monitoring wells based on specific information about the CCS project, including injection rate and volume, geology, the presence of artificial penetrations and other factors;*

(6) *The monitoring frequency and spatial distribution of monitoring wells based on any modeling results required by subsection C.2.4.1;*

(7) *A demonstration of external mechanical integrity pursuant to subsection C.4.2 at least once per year until the injection well is plugged, and, if required by the Executive Officer, a casing inspection log pursuant to requirements at subsection C.4.2(c) at a frequency established in the Testing and Monitoring Plan;*

(8) *A pressure fall-off test at least once every five years, pursuant to subsection C.4.3.1.5, unless more frequent testing is required by the Executive Officer based on site-specific information;*

(9) Testing and monitoring to track the extent of the CO_2 plume, and the presence or absence of elevated pressure;

(10) Surface air monitoring and soil gas monitoring to detect potential movement of CO_2 in the shallow subsurface or atmosphere;

(11) At a minimum, the monitoring plan must stipulate and include:

(A) The frequency of data acquisition;

(B) A record keeping plan;

(C) The frequency of instrument calibration activities;

(D) The QA/QC provisions on data acquisition, management, and record keeping that ensures it is carried out consistently and with precision;

(E) The role of individuals performing each specific monitoring activity; and

(F) Methods to measure and quantify the following data:

1. Quantity of CO_2 emitted from the capture site;

2. Quantity of CO_2 sold to third parties (e.g., for enhanced oil recovery) including sufficient measurements to support data required; and

3. Quantity of CO_2 injected into each well in the CCS project, metered at the wellhead.

(12) Any additional monitoring, as required by the Executive Officer, necessary to support, upgrade, and improve computational modeling of the Storage Complex ~~AOR~~ evaluation required under subsection C.2.4.1;

(13) The CCS Project Operator must periodically review the Testing and Monitoring Plan to incorporate monitoring data collected under this subsection, operational data collected under subsection C.3, and the most recent Storage Complex ~~AOR~~ reevaluation performed under subsection C.2.4.4; and

(14) The CCS Project Operator must review the Testing and Monitoring Plan no less than once every five years. Based on this review, the CCS Project Operator must submit an amended Testing and Monitoring Plan or demonstrate to the Executive Officer that no amendment to the Testing and Monitoring Plan is needed. Any amendments to the Testing and Monitoring Plan must be approved by the Executive Officer. Amended plans or demonstrations must be

submitted to the Executive Officer as follows:

(A) Within one year of a~~n~~ Storage Complex ~~AOR~~ reevaluation; or

(B) When required by the Executive Officer.

4.2 Mechanical Integrity Testing

[...]

5.2 Post-Injection Site Care and Site Closure

(a) The CCS Project Operator must prepare, maintain, and comply with a plan for post-injection site care and site closure that meets the requirements of subsection C.5.2(a)(2) and C.5.2(b).

(1) The CCS Project Operator must submit the Post-Injection Site Care and Site Closure Plan as a part of the application for Sequestration Site Certification.

(2) Post-Injection Site Care and Site Closure Plan. The plan for site care and closure must include the following information:

(A) The pressure differential between pre-injection and predicted post- injection pressures in the sequestration zone, and the predicted timeframe in which pressure is expected to ~~decrease to pre- or close to pre-injection levels~~ stabilize;

(B) A depiction of the predicted position of the CO_2 free-phase plume and associated pressure front at site closure as demonstrated in the Storage Complex ~~AOR~~ evaluation and computational modeling required at subsections C.2.4 and C.2.4.1;

(C) A description of post-injection monitoring location, methods, and proposed frequency; and

(D) A proposed schedule for submitting post-injection site care monitoring results to the Executive Officer.

(3) Upon injection completion, the CCS Project Operator must either submit an amended Post-Injection Site Care and Site Closure Plan, or demonstrate to the Executive Officer through monitoring data and modeling results that no amendment to the plan is needed. Any amendments to the Post-Injection Site

Care and Site Closure Plan must be approved by the Executive Officer and incorporated into the Permanence Certification.

(4) *At any time during the life of the CCS project, the CCS Project Operator may modify and resubmit the Post-Injection Site Care and Site Closure Plan for the Executive Officer's approval within 30 days of such change.*

(b) *Post-injection site care and monitoring:*

(1) *The CCS Project Operator must monitor the site following injection completion to determine the position of the free-phase CO_2 plume and pressure front, and demonstrate that no credited fluids are leaking out of the storage complex, as specified in the Testing and Monitoring Plan and the Post-Injection Site Care and Site Closure Plan.*

(2) *After injection is complete, the CCS Project Operator must continue to conduct monitoring as specified in this section and the Executive Officer-approved Post-Injection Site Care and Site Closure Plan ~~for a minimum of 100 years~~.*

(3) *Post-injection site care and monitoring requirements are as follows:*

(A) *Within 24 months after injection is complete, all injection (and production, if applicable) wells associated with the CCS project must be plugged and abandoned pursuant subsection C.5.1(d), with the exception of any wells that the CCS Project Operator plans to transition into observation or monitoring wells.*

(B) *Monitoring and observation wells must remain open, and in active monitoring mode, until the CO_2 plume reaches a stable state in which the pressure ~~front~~ is no longer increasing ~~in radius~~ (or is decreasing) and conforms to model predictions pursuant to subsection C.2.4.1, and until CARB agrees <u>a substantial trend in</u> plume stabili<u>zation</u>~~ty~~ has <u>been demonstrated to the satisfaction of the Executive Officer.</u> ~~occurred~~.*

(C) *If a monitoring well is discovered to be leaking at any time during the post-injection monitoring period, the CCS Project Operator must take all necessary measures to identify the cause of the leak and remediate it. If the leak cannot be remediated, the well must immediately be plugged and abandoned pursuant to subsection C.5.1(d).*

(D) *As part of post-injection monitoring,if required by the ~~and pursuant to the monitoring timeline as specified in the~~ Post-Injection Site Care and Site Closure Plan, the CCS Project Operator must <u>in conformance with the</u>*

<u>specified timeline</u>:

1. *Conduct ~~quarterly~~ bottom-hole pressure tests in the monitoring wells in order to track the position of the pressure front;*

2. *Use appropriate best-practice methods to map the position of the free-phase CO_2 plume and pressure front; and*

3. *Periodically update the ~~AOR~~<u>Storage Complex</u> delineation pursuant to subsection C.2.4 to determine if any corrective action is necessary ~~and to establish if~~ <u>until a trend in</u> CO_2 plume <u>stability has been demonstrated</u> ~~has stabilized~~.*

4. *Conduct leak detection checks at each well that is part of the CCS project, and in the near surface close to each plugged and abandoned well until the CO_2 plume ~~has~~ stabiliz~~ed~~<u>ation trend is demonstrated to the satisfaction of the Executive Officer</u>.*

(E) Once the <u>trend in</u> CO_2 plume stability has been demonstrated, all CCS project wells may be <u>plugged and</u> abandoned following subsection C.5.1(d).

(F) The CCS Project Operator must submit the results of all monitoring performed according to the schedule identified in the Post-Injection Site Care and Site Closure Plan.

~~*1. Soil-gas and surface-air monitoring at, and within 10 ft of, the wellhead or well pad; and*~~

~~*2. Visual inspection of the wellhead and the land surface within a 100 ft radius of the wellhead or well pad.*~~

(G) The CCS Project Operator must submit the results of all monitoring performed according to the schedule identified in the Post-Injection Site Care and Site Closure Plan.

(c) Notice of intent for site closure. The CCS Project Operator must notify the Executive Officer at least 120 days before site closure. At this time, if any changes have been made to the original Post-Injection Site Care and Site Closure Plan, the CCS Project Operator must also provide the revised plan.

(d) After the Executive Officer has authorized site closure, the CCS Project Operator must plug all monitoring wells as specified in the Post-Injection Site Care and Site Closure Plan, in a manner in which will not allow movement of injection or formation fluids out of the storage complex. At the direction of the Executive Officer, the CCS Project Operator must also restore the site to its pre-injection condition.

(e) The CCS Project Operator must submit a site closure report to the Executive Officer within 90 days of site closure, which must thereafter be retained at a location designated by the Executive Officer for 10 years. The report must include:

(1) Documentation of appropriate injection and monitoring well plugging and abandonment as specified in subsections C.5.1, C.5.2(b)(3)(A), and C.5.2(b)(3)(G). The CCS Project Operator must provide a copy of a survey plat, which has been submitted to the local zoning authority designated by the Executive Officer. The plat must indicate the location of the injection well relative to permanently surveyed benchmarks;

(2) Documentation of appropriate notification and information to such state, federal, local, and tribal authorities that have authority over drilling activities to enable such state, federal, local, and tribal authorities to impose appropriate conditions on subsequent drilling activities that may penetrate the storage complex; and

(3) Records reflecting the nature, composition, and volume of the CO_2 stream.

(f) Within 30 days each CCS Project Operator must record a notation on the deed to the CCS project property or any other document that is normally examined during title search that will in perpetuity provide any potential purchaser of the property the following information:

(1) The fact that land has been used to sequester CO_2;

(2) The name of the state agency and local authority with which the survey plat was filed; and

(3) The volume of fluid injected, the sequestration zone into which it was injected, and the period over which injection occurred.

(g) The CCS Project Operator must retain for 10 years following site closure, records collected during the post-injection site care period.

[...]

7. Financial Responsibility

(a) The CCS Project Operator of a certified CCS project must demonstrate and maintain financial responsibility and resources as determined by the Executive Officer that meets the following conditions:

(1) The financial responsibility instrument(s) used must be from the following list of

qualifying instruments:

(A) Trust Funds;

(B) Surety Bonds;

(C) Letter of Credit;

(D) Insurance;

(E) Self-Insurance (i.e., Financial Test and Corporate Guarantee);

(F) Escrow Account; and

(G) Any other instrument(s) satisfactory to the Executive Officer.

(2) The qualifying instrument(s) must be sufficient to cover the cost of:

(A) Corrective action (that meets the requirements of subsection C.2.4.3);

(B) Well plugging and abandonment (that meets the requirements of subsection C.5.1);

(C) Post-injection site care and site closure (that meets the requirements of subsection C.5.2); and

(D) Emergency and remedial response (that meets the requirements of subsection C.6).

(3) The financial responsibility instrument(s) must be sufficient to address the risk of ~~potential endangerment of public health and the environment via~~ atmospheric leakage of CO_2, as determined by Appendix G. Post injection, the CCS project's buffer account balance may be utilized solely to address the atmospheric leakage risk pursuant to this section and B.3(f).

(4) The qualifying financial responsibility instrument(s) must comprise protective conditions of coverage.

(A) Protective conditions of coverage must include at a minimum: cancellation, renewal, and continuation provisions, specifications on when the provider becomes liable following a notice of cancellation if there is a failure to renew (with a new qualifying financial instrument), as well as requirements for the provider to meet a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.

1. For purposes of this part, a CCS Project Operator must provide that their *financial mechanism may not cancel, terminate or fail to renew except for failure to pay such financial instrument. If there is a failure to pay the financial instrument, the financial institution may elect to cancel, terminate, or fail to renew the instrument by sending notice by certified mail and an electronic format to the CCS Project Operator and the Executive Officer. The cancellation must not be final for 120 days after receipt of cancellation notice. The CCS Project Operator must provide an alternate financial responsibility demonstration within 60 days of notice of cancellation, and if an alternate financial responsibility demonstration is not acceptable (or possible), any funds from the instrument being cancelled must be released within 60 days of notification by the Executive Officer to complete required activities that the financial responsibility instrument are expected to cover, as described in subsection C.7(a)(2).*

2. *For purposes of this part, the CCS Project Operator must renew all financial instruments, if an instrument expires, for the entire term of the CCS project <u>to the extent that financial instrument remains necessary for the CCS Project Operator to fulfill the financial responsibilities as calculated for the applicable phase of the CCS project</u>. The instrument may be automatically renewed as long as the CCS Project Operator has the option of renewal at the face amount of the expiring instrument. The automatic renewal of the instrument must, at a minimum, provide the holder with the option of renewal at the face amount of the expiring financial instrument.*

3. *Cancellation, termination, or failure to renew may not occur and the financial instrument will remain in full force and effect in the event that on or before the date of expiration: (1) the Executive Officer deems the CCS project abandoned, (2) the permit is terminated or revoked or a new permit is denied, (3) closure is ordered by the Executive Officer or a U.S. district court or other court of competent jurisdiction, (4) the CCS Project Operator is named as debtor in a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code, or (5) the amount due is paid.*

(5) The qualifying financial responsibility instrument(s) must be approved by the Executive Officer.

(A) The financial responsibility demonstration must be considered and approved by the Executive Officer for all phases of the CCS project prior to Permanence Certification following subsection C.1.1.

(B) The CCS Project Operator must provide updated information related to their financial responsibility instrument(s) when/if there are any changes. This information must be provided to the Executive Officer within 30 days of such a change. The Executive Officer will evaluate, within a reasonable time, the financial responsibility demonstration to confirm that the instrument(s) used

remain adequate for use. The CCS Project Operator must maintain financial responsibility requirements regardless of the status of the Executive Officer's review of the financial responsibility demonstration.

(C) The Executive Officer may disapprove the use of a financial instrument if he determines that it is not sufficient to meet the requirements of this section.

(6) The CCS Project Operator must demonstrate financial responsibility by using one or multiple qualifying financial instruments for specific phases of the CCS project.

(A) In the event that the CCS Project Operator combines more than one instrument for a specific CCS phase (e.g., well plugging), such combination must be limited to instruments that are not based on financial strength or performance (i.e., self-insurance or performance bond), for example trust funds, surety bonds guaranteeing payment into a trust fund, letters of credit, escrow account, and insurance. In this case, it is the combination of mechanisms, rather than the single mechanism, which must provide financial responsibility for an amount at least equal to the current cost estimate.

(B) When using a third-party instrument to demonstrate financial responsibility, the CCS Project Operator must provide a proof that the third-party providers either have passed financial strength requirements based on credit ratings, or has met a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.

(C) A CCS Project Operator using certain types of third-party instruments must establish a standby trust to enable CARB to be party to the financial responsibility agreement without CARB being the beneficiary of any funds. The standby trust fund must be used along with other financial responsibility instruments (e.g., surety bonds, letters of credit, or escrow accounts) to provide a location to place funds if needed.

(D) A CCS Project Operator may deposit money to an escrow account to cover financial responsibility requirements, and this account must segregate funds sufficient to cover estimated costs for CCS project financial responsibility from other accounts and uses.

(E) A CCS Project Operator or its guarantor may use self-insurance to demonstrate financial responsibility for CCS projects. In order to satisfy this requirement the CCS Project Operator must meet a tangible net worth of an amount approved by the Executive Officer, have a Net working capital and tangible net worth each at least six times the sum of the current well plugging, post injection site care and site closure cost, have assets located in

the United States amounting to at least 90 percent of total assets or at least six times the sum of the current well plugging, post injection site care and site closure cost, and must submit a report of its bond rating and financial information annually. In addition the CCS Project Operator must either: Have a bond rating test of AAA, AA, A, or BBB as issued by Standard & Poor's, Aaa, Aa, A, or Baa as issued by Moody's, or meet all of the following five financial ratio thresholds: (1) A ratio of total liabilities to net worth less than 2.0, (2) a ratio of current assets to current liabilities greater than 1.5, (3) a ratio of the sum of net income plus depreciation, depletion, and amortization to total liabilities greater than 0.1, (4) A ratio of current assets minus current liabilities to total assets greater than −0.1, and (5) a net profit (revenues minus expenses) greater than 0.

(F) A CCS Project Operator who is not able to meet corporate financial test criteria may arrange a corporate guarantee by demonstrating that its corporate parent meets the financial test requirements on its behalf. The parent's demonstration that it meets the financial test requirement is insufficient if it has not also guaranteed to fulfill the obligation for the CCS Project Operator.

(G) A CCS Project Operator may obtain an insurance policy to cover the estimated costs of CCS activities requiring financial responsibility. This insurance policy must be obtained from a third-party provider.

(b) The CCS Project Operator must maintain financial responsibility and resources until:

(1) The Executive Officer receives and approves the completed Post-Injection Site Care and Site Closure Plan; and

(2) The Executive Officer approves site closure.

(c) The CCS Project Operator may be released from financial instrument in the following circumstances:

(1) The CCS Project Operator has completed the phase of the CCS project for which the financial instrument was required and has fulfilled all its financial obligations as determined by the Executive Officer, including obtaining financial responsibility for the next phase of the CCS project, if required; or

(2) The CCS Project Operator has submitted a replacement financial instrument and received written approval from the Executive Officer accepting the new financial instrument and releasing the CCS Project Operator from the previous financial instrument.

(d) The CCS Project Operator must have a detailed written estimate, in current dollars, of the cost of performing corrective action on wells in the ~~AOR~~Storage Complex, plugging the well(s), post-injection site care and site closure, and emergency and remedial response.

(1) The cost estimate must be performed for each phase separately and must be based on the costs to the regulatory agency of hiring a third party to perform the required activities. A third party is a party who is not within the corporate structure of the CCS Project Operator.

(2) During the active life of the CCS project, the CCS Project Operator must adjust the cost estimate for inflation within 60 days prior to the anniversary date of the establishment of the financial instrument(s) used to comply with subsection C.7(a) and provide this adjustment to the Executive Officer. The CCS Project Operator must also provide the Executive Officer written updates of adjustments to the cost estimate within 60 days of any amendments to the ~~AOR~~Storage Complex and Corrective Action Plan, the Well Plugging and Abandonment Plan, the Post-Injection Site Care and Site Closure Plan, and the Emergency and Remedial Response Plan.

(3) Any decrease or increase to the initial cost estimate must be approved by the Executive Officer. During the active life of the CCS project, the CCS Project Operator must revise the cost estimate no later than 60 days after the Executive Officer has approved the request to modify the ~~AOR~~Storage Complex and Corrective Action Plan, the Injection Well Plugging and Abandonment Plan, the Post- Injection Site Care and Site Closure Plan, and the Emergency and Remedial Response Plan, if the changes in the plan increases the cost. If the change to the plans decreases the cost, any withdrawal of funds must be approved by the Executive Officer. Any decrease to the value of the financial assurance instrument must first be approved by the Executive officer. The revised cost estimate must be adjusted for inflation as specified at subsection C.7(c)(2).

(4) Whenever the current cost estimate increases to an amount greater than the face amount of a financial instrument currently in use, the CCS Project Operator, within 60 days after the increase, must either cause the face amount to be increased to an amount at least equal to the current cost estimate and submit evidence of such increase to the Executive Officer, or obtain other financial responsibility instruments to cover the increase. Whenever the current cost estimate decreases, the face amount of the financial assurance instrument may be reduced to the amount of the current cost estimate only after the CCS Project Operator has received written approval from the Executive Officer.

(e) The CCS Project Operator must notify the Executive Officer by an electronic format and certified mail of adverse financial conditions such as bankruptcy that may

affect the ability to carry our injection well plugging and post-injection site care and site closure.

(1) In the event that the CCS Project Operator or the third-party provider of a financial responsibility instrument is going through a bankruptcy, the CCS Project Operator must notify the Executive Officer by certified mail and an electronic format of the commencement of a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code, naming the CCS Project Operator as debtor, within 10 days after commencement of the proceeding.

(2) A guarantor of a corporate guarantee must make such a notification to the Executive Officer if he/she is named as debtor, as required under the terms of the corporate guarantee.

(3) A CCS Project Operator who fulfills the requirements of subsection C.7(a) by obtaining a trust fund, surety bond, letter of credit, escrow account, or insurance policy will be deemed to be without the required financial assurance in the event of bankruptcy of the trustee or issuing institution, or a suspension or revocation of the authority of the trustee institution to act as trustee of the institution issuing the trust fund, surety bond, letter of credit, escrow account, or insurance policy. The CCS Project Operator must establish other financial assurance within 60 days after such an event.

(f) The CCS Project Operator must provide an adjustment of the cost estimate to the Executive Officer within 60 days of notification by the Executive Officer, if the Executive Officer determines during the annual evaluation of the qualifying financial responsibility instrument(s) that the most recent demonstration is no longer adequate to cover the cost of corrective action (as required by subsection C.2.4.3), well plugging and abandonment (as required by subsection C.5.1), post-injection site care and site closure (as required by subsection C.5.2), and emergency and remedial response (as required by subsection C.6).

(g) The use and length of pay-in-periods for trust funds or escrow accounts must be approved by the Executive Officer.

[...]

Appendix G. Determination of a CCS Project's Risk Rating for Determining its <u>Risk of Atmospheric Leakage and</u> Contribution to the LCFS Buffer Account

<u>This appendix is to be utilized to determine a CCS project's risk of atmospheric leakage pursuant to C.7(a)(3) and its corresponding duty to contribute to an LCFS Buffer Account</u>. CARB maintains ~~an~~ LCFS Buffer Account<u>s</u> to insure against the risk of CO_2 leakage credited for sequestration and credit invalidation. A percentage of a CCS project's LCFS credits must be contributed to the LCFS Buffer Account pursuant to the Regulation. The specific percentage of the contribution is determined by a CCS project's risk rating, based on the potential for CO_2 leakage associated with different types of risks and project-specific circumstances.

(a) The CCS Project Operator or Authorized Project Designee is required to determine the project's invalidation risk rating prior to submitting their application for CCS project certification, ~~and~~ to recalculate it every time the CCS project undergoes verification<u>, and to recalculate it after injection has terminated and the Post-Injection Site Care and Site Closure Plan has been approved or re-affirmed</u>.

(b) When estimated risk values and associated mitigation measures are updated, any adjustments to the invalidation risk ratings will affect only the current and future year contributions to the Buffer Account.

(c) Factors that contribute to CCS project risk rating are classified into the categories identified in Table G1.

(d) The CCS project risk rating must be determined using the tables and methods in this appendix, which are designed to identify and quantify the specific types of risks that may lead to CO_2 leakage and subsequent credit invalidation, based on project-specific factors. The CCS Project Operator or Authorized Project Designee must determine the contribution to the invalidation risk rating for each risk type in Table G1.

(1) Financial risk: Financial failure of an organization resulting in bankruptcy can lead to dissolution of agreements and management activities to recover losses, which may increase the potential for CO_2 leakage and credit invalidation. CCS projects that demonstrate high financial strength are expected to have lower financial risk. A financial rating for the CCS Project Operator from Moody's, Standard & Poor's, and Fitch, can be used to demonstrate the project operator's financial strength. Projects that demonstrate high financial strength are expected to have lower risk for leakage and credit invalidation and can contribute less to the Buffer Account.

(2) Social risk: Social risks exist due to changing government policies, regulations, rule of law, order and security, and general economic conditions. The risks of social or political actions leading to leakage and credit invalidation could be

significant and differ across countries or regions. The performance indicator from the World Justice Project Rule of Law Index can be used to demonstrate the social risk status of the country or region where a CCS project is located. Projects that demonstrate low social risks are expected to have lower risk for leakage and credit invalidation and will contribute less to the Buffer Account. The World Justice Project Rule of Law Index uses household and expert surveys to measure how the rule of law is experienced and perceived by the general public worldwide. The rule of law performance is measured using 44 indicators across eight primary rule of law factors: Constraints on Government Powers, Absence of Corruption, Open Government, Fundamental Rights, Order and Security, Regulatory Enforcement, Civil Justice, and Criminal Justice. Each of the primary rule of law factors is scored and ranked globally and against regional and income peers.

(3) Management risk: Management risk is the risk of management activities or failure to follow best project management practices (such as restricting site access) that directly or indirectly could lead to leakage and credit invalidation. For a typical CCS project, illegal removals of the components of surface injection facilities such as an injection well head during the injection operation or any time before well plugging can potentially lead to a CO_2 *leakage and credit invalidation. Illegal removals of the components of surface injection facilities can occur either by trespass or outside of a planned set of management activities that are controlled by regulation. Illegal removals of the components of surface injection facilities are more likely to occur when there is a lack of controls and enforcement activities. Projects that demonstrate quality management of access controls and enforcement are expected to have less management risk and thus lower risk for leakage and credit invalidation and can contribute less to the Buffer Account.*

(4) Site risk: Proper site selection is key to minimize the risk of leakage and credit invalidation. Section C.2.1 sets forth a set of minimum site selection criteria to minimize the risk of CO_2 *leakage. Project operators have the option to go beyond the minimum criteria and contribute less to the Buffer Account.*

(5) Well integrity risk: If wells are not constructed to the proper requirements, or if well maintenance, operations, and plugs do not follow appropriately prescribed plans, wells may become potential conduits for leakage and cause credit invalidation. It is essential to follow appropriate construction requirements and prescribed operating plans to ensure that injection does not compromise the well or fracture the injection formation or confining zone. The U.S. EPA (U.S. Environmental Protection Agency) class VI well standards under the UIC (Underground Injection Control) program are designed for safe CO_2 *injection and protection of underground drinking water resources. The U.S. EPA class VI well standards are designed to avoid the movement of* CO_2 *and other fluid from the storage complex to unauthorized zones, which in most cases*

will prevent the release of CO_2 to the atmosphere. Conformance to the U.S. EPA class VI well regulations is an indicator of minimizing the risk of CO_2 leakage using wells a conduit. Since wells are the primary remaining risk factor if a quality sequestration site has been chosen, projects that demonstrate that all of their wells meet USEPA class VI well or equivalent requirements can contribute less to the Buffer Account.

Table G.1. *CCS project contribution to CCS project risk rating <u>during injection phase of project</u> based on risk types*

Risk type	***Risk category***	***Risk Rating Contribution***
Financial	*Low Financial Risk:* *CCS project operators that demonstrate their company has:* ● *a Moody's rating of A or better; or* ● *an equivalent rating from Standard & Poor's, and Fitch*	*0%*
	Medium Financial Risk: *CCS project operators that demonstrate their company has:* ● *a Moody's rating of B or better meets; or* ● *an equivalent rating from Standard & Poor's, and Fitch*	*1%*
	High Financial Risk: *CCS project operators that cannot make one of the two demonstrations above*	*2%*
Social	*Low Social Risk:* *CCS projects located in countries or regions ranked among the top 20th percentile based on the World Justice Project Rule of Law Index*	*0%*
	Medium Social Risk: *CCS projects located in countries or regions ranked between the 20th and 50th percentile based on the World Justice Project Rule of Law Index*	*1%*
	High Social Risk: *CCS projects located in countries or regions that are not ranked, or are ranked below the 50th percentile based on the World Justice Project Rule of Law Index*	*3%*
Management	*Low Management Risk:* *Demonstrated surface facility access control, e.g., injection site is fenced and well protected*	*1%*

	Higher Management Risk: *Poor or no surface facility access control, e.g., injection site is open, or not fenced or protected*	*2%*
Site	*Low Site Risk:* *Selected site has more than two good quality confining layers above the sequestration zone and a dissipation interval below the sequestration zone*	*1%*
	Higher Site Risk: *Selected site meets the minimum site selection criteria but does not meet the above site criteria*	*2%*
Well integrity	*Low Well Integrity Risk:* *All wells for the CCS project meet USEPA class VI well or equivalent requirements*	*1%*
	Higher Well Integrity Risk: *The CCS project has wells that do not meet USEPA class VI well or equivalent requirements*	*3%*

(e) A Project Operator must use Table G2 to summarize and report to CARB the CCS project's risk rating and contribution to the Buffer Account for each risk type.

Table G2. *CCS Project Contribution to the Buffer Account for Each Risk Type*

Risk type	***Risk category***	***Risk Rating Contribution***
Financial	☐ *Low Financial Risk* ☐ *Medium Financial Risk* ☐ *High Financial Risk*	
Social	☐ *Low Social Risk* ☐ *Medium Social Risk* ☐ *High Social Risk*	
Management	☐ *Low Management Risk* ☐ *Higher Management Risk*	
Site	☐ *Low Site Risk* ☐ *Higher Site Risk*	
Well integrity	☐ *Low Well integrity Risk* ☐ *Higher Well integrity Risk*	

<u>***Table G.3.*** *CCS project contribution to CCS project risk rating during post-injection phase of project based on risk types (with proposed changes marked relative to Table G.1)*</u>

Risk type	**Risk category**	**Risk Rating Contribution**
Financial	*Low Financial Risk:* *CCS project operators that demonstrate their company has:* ● *a Moody's rating of A or better; or* ● *an equivalent rating from Standard & Poor's, and Fitch*	*0%*
	Medium Financial Risk: *CCS project operators that demonstrate their company has:* ● *a Moody's rating of B or better meets; or* ● *an equivalent rating from Standard & Poor's, and Fitch*	*1%*
	High Financial Risk: *CCS project operators that cannot make one of the two demonstrations above*	*2%*
Social	*Low Social Risk:* *CCS projects located in countries or regions ranked among the top 20^{th} percentile based on the World Justice Project Rule of Law Index*	*0%*
	Medium Social Risk: *CCS projects located in countries or regions ranked between the 20^{th} and 50^{th} percentile based on the World Justice Project Rule of Law Index*	*1%*
	High Social Risk: *CCS projects located in countries or regions that are not ranked, or are ranked below the 50^{th} percentile based on the World Justice Project Rule of Law Index*	*3%*
Management	*Low Management Risk:* *Demonstrated surface facility access control, e.g., injection site is fenced and well protected, and proven compliance history of highly competent management control of CCS project during injection phase.*	*0~~1~~%*
	Higher Management Risk: *Poor or no surface facility access control, e.g., injection site is open, or not fenced or protected and/or poor management control history during injection phase.*	*2%*
Site	*Low Site Risk:* *CCS Project Operator has submitted timely reports of GHG emissions reductions and monitoring results during injection phase. Reports have included measurements of relevant parameters sufficient to confirm permanent~~that the~~ sequestration of CO_2. Data quality management has been sufficient to support*	*~~1~~0%*

	quantification and verification of CO_2 sequestered with no indications of significant site risk. ~~*Selected site has more than two good quality confining layers above the sequestration zone and a dissipation interval below the sequestration zone*~~	

Site	*Medium Site Risk:* *CCS Project Operator has submitted timely reports of GHG emissions reductions and monitoring results during injection phase. Reports have included measurements and analysis of relevant parameters sufficient to confirm that the ~~sequestration~~ permanent storage of CO_2 has been attained. Data quality management has been sufficient to support quantification and verification of CO_2 sequestered with only minor indications of site risk.* *Higher Site Risk: Project history suggests more than minor site risk over 100-year post-injection period.* *~~Selected site meets the minimum site selection criteria but does not meet the above site criteria~~*	*1~~2~~%* *2%*
Well integrity	*Low Well Integrity Risk:* *All wells for the CCS project meet USEPA class VI well or equivalent requirements with no indications of unmitigated well integrity issues during injection period.*	*~~1~~0%*
	Higher Well Integrity Risk: *The CCS project has wells that do not meet USEPA class VI well or equivalent requirements or has ~~show~~ indications of unmitigated well integrity issues during injection period.*	*3%*

(f)

The CCS project's overall risk rating and contribution to the Buffer Account is calculated using Equation G.1, below:

$$\begin{aligned} \mathit{CCS\ Project\ Risk\ Rating} &= 100\% \\ &- \big[(100\% - Risk_{Financial}) \times (100\% - Risk_{Social}) \\ &\times \big(100\% - Risk_{Management}\big) \times (100\% - Risk_{Site}) \\ &\times \big(100\% - Risk_{Well\ Integrity}\big)\big] \end{aligned} \tag{G.1}$$