Submitted electronically
Clerk of the Board
California Air Resources Board
1001 I Street
Sacramento, CA 95814
https://www.arb.ca.gov/lispub/comm/bclist.php

April 23, 2018

Re: Clean Air Task Force comments on Carbon Capture and Sequestration Protocol under the Low Carbon Fuel Standard

Dear Clerk of the Board,

Clean Air Task Force (CATF) appreciates the continued opportunity to provide comments to California Air Resources Board (CARB) on the proposed amendments to the Low Carbon Fuel Standard (LCFS) regulation, specifically Appendix B – Attachment 1: Carbon Capture and Sequestration Protocol (Protocol).

CATF believes that any successful solution to preventing the worst effects of climate change will invariably have to include better and cheaper low-carbon technologies that can be deployed at industrial scale, with carbon capture and storage (CCS) representing one of the key feasible strategies. For more than two decades CATF has applied its technical and policy expertise to develop solutions to the climate challenge. Most recently, CATF succeeded in a joint-effort to extend and expand federal tax incentives (45Q) encouraging carbon capture utilization and storage.

CATF appreciates the effort that the CARB has invested in developing the Protocol and strongly supports CCS as an integral part of the LCFS. CATF believes CCS can play an important role in the reduction of fossil carbon emissions in California.

This letter provides our comments on the Protocol, which we believe will serve to strengthen it. We recognize that many hours have been spent by the staff developing the draft and we appreciate the opportunities that CARB has provided for input over the past several years.[1] Please note that we

[1] John Thompson, CATF, PowerPoint, "CCS Perspectives and Recommendations on Quantification Methodologies," (Feb. 12, 2016), *available at*: https://www.arb.ca.gov/cc/ccs/meetings/CATF_Presentation_2-12-16.pdf; Bruce Hill, CATF, PowerPoint "Considerations in Developing QM for EOR Storage," (Aug. 23, 2016), *available at:* https://www.arb.ca.gov/cc/ccs/meetings/CATF_Presentation_8-23-16.pdf; Bruce Hill, CATF, Testimony at ARB Public Workshop, (Feb. 12, 2016), *available at:* https://www.arb.ca.gov/cc/ccs/meetings/CATF_Comments_2-12-16.pdf; Bruce Hill, CATF, "Comments to ARB on Quantitative Methodology, Accounting," (Apr. 28, 2016), *available at:* https://www.arb.ca.gov/cc/ccs/meetings/Bruce_Hill_CATF_Comments_4-28-16.pdf; Letter from Jeffrey Bobeck, Global Carbon Capture and Storage Institute, *et al.*, to Alexander Mitchell, ARB, (May 30, 2017), *available at:* https://www.arb.ca.gov/cc/ccs/meetings/Various_Comments_5-30-17.pdf; Letter from Jeffrey Bobeck, Global Carbon Capture and Storage Institute, *et al.*, to Samuel Wade, ARB (Oct. 20, 2017), *available at*: https://www.arb.ca.gov/fuels/lcfs/workshops/10202017_coalition.pdf; Letter from Jeffrey Bobeck, Global Carbon

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have also co-submitted, with Dr. Susan Hovorka from the University of Texas, an edited version of the Protocol. That submission, however, did not include CATF's input pertaining to sections B.3, C.1, C.5, C.7, and appendix G. Those provisions are conceptually addressed in this letter, with proposed language to implement the recommendations included in the attached redline.

I. A Performance-Based Approach Will Provide Better Long-Term Storage Security.

A performance-based approach is necessary to secure subsurface storage of carbon dioxide (CO_2) in saline projects and will provide the added benefit of better integrating the requirements in the Protocol for use in commercial enhanced oil recovery (EOR) projects. 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.

In a performance-based approach, project operators build a model of the storage complex, identify areas of potential leakage risk, and tailor the monitoring plan to the risk model and local geology. A performance-based approach will enable operators and CARB to effectively determine, for each different project, what combination of performance criteria and monitoring will provide a sufficient level of certainty that CO_2 will be securely stored over the 100-year permanence period and well beyond. In the case of EOR, monitoring data may include CO_2 conformance metrics already in use by the project. The plan 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 measurement and modeling steps 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. Dr. Hovorka has submitted some suggested changes to the Protocol, accompanied by our letter of support, which we believe will help make it more performance based.

II. "Storage Complex" and "Elevated Pressure" Should Define Investigation and Monitoring.

The "area of review" (AOR) and plume and pressure front concepts are adopted from the Federal Underground Injection Control Rule 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 CO_2 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 emanating updip from the formation - as possibly present California's mountainous regions.

Capture and Storage Institute, *et al.*, to Samuel Wade, ARB (Dec. 4, 2017), *available at*: https://www.arb.ca.gov/fuels/lcfs/workshops/12042017_coalition.pdf.

Second, the pressure front itself can be a misleading conceptual model for describing how injected CO_2 interacts with reservoir formations, given the subsurface heterogeneity in mineralogy, grain size, cements, composition, and structures. Pressure may extend outward from an injection well, but it is incorrect to think of it as a circumference of pressure extending radially from the injected CO_2 location, but better instead to conceptualize response as "areas of elevated pressure." Furthermore, in EOR projects, injection wells are surrounded by production wells which generate low pressure around them, and therefore a pressure front approach cannot effectively be applied to EOR projects. To easily remedy this, Dr. Hovorka's edited Protocol submission further recommends elimination of the word "front" to be replaced globally in the document with "elevated", thus, "elevated pressure."[2] In concert with this change, we recommend replacement of the "area of review" (AOR) 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.[3] Under this recommended approach, the terms "elevated pressure" and "storage complex" will 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 will be risks that are identified and corrective action will be taken to avoid leakage. These conditions will then be monitored to determine if the corrective action was successful, and to determine whether these features pose risks to permanence. The term "area of review" (the surface overlying the storage complex) should then be only used to define important *surface* resources.

In summary, the maximum acceptable space for the CO_2 plume to migrate should be a volume rather than an area. As an example, a horizontal well drilled outside an AOR might be deviated into the storage complex volume at depth. A three-dimensional review will assess risk from all sources. Therefore, for all projects, we recommend that CARB 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.

III. Improving Storage Security of Enhanced Oil Recovery Projects.

While the Protocol states that it anticipates EOR, the Protocol as drafted takes an approach that is largely focused on saline storage, similar to the Environmental Protection Agency's Underground Injection Control Rule, Class VI. In order to better improve the security of CO_2 stored in oilfields, and, at the same time, encourage those projects, the design of the Protocol must take into account the inherent differences in pressure management during CO_2 injection for EOR projects that plan to store CO_2 rather than taking a saline project centric approach.

We recommend the following changes to improve the applicability of the rule to EOR:

- Critical consideration must be given to the fact that CO_2 injection and resultant changes in formation pressure are managed through production in EOR. In EOR fields, injector wells are at the center of a pattern of production wells which produce effective low-pressure zones, and therefore the concept of a pressure front is not relevant. One simple modification in the Protocol, as described above, would significantly improve the efficacy of the overall approach by changing the term "pressure front" to areas of "elevated pressure" globally, throughout the Protocol.

- The Protocol should require measuring fluid flow at the correct points to obtain high quality accounting. Currently 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 history matching and analyzing past production and to expend less effort in collecting 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 currently requires substantial due diligence to identify oil wells in the project area, however, it could be strengthened by requiring a description of the completeness of well database, as completeness may vary from state to state.
- Accounting is needed for off-lease migration. Not new to the industry, off-lease migration can be a significant problem for operators, as they may lose out-of-pattern oil or CO_2. Operators encountering this problem are routinely using conformance metrics (a form of monitoring) to track CO_2. Where CO_2 loss is a risk, water curtains can be set up (injected water blocking CO_2) and production at the boundary of a pattern or lease may, and discussions initiated with adjacent operators. Although the CO_2 may migrate outside the project boundary, it still may be largely 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 be included in the tools recommended for monitoring CO_2 in EOR fields as they will help identify off-lease migration.

IV. Baseline Monitoring Approach.

Baseline soil flux monitoring is a cornerstone strategy of the Protocol, which could result in false positives or miss leakage altogether because of a proven lack of broad reliability, with results 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. Using a baseline strategy, a false indicator of leakage will trigger further investigation which may require substantial investment. Moreover, methodologies and technologies will evolve and therefore monitoring strategies should take into account that it may be a challenge to compare the results of newer technologies with older technologies in the future.

In contrast, soil baselines have been demonstrated to be unreliable and may lead to greater uncertainty and wasted monitoring resources such as in the Kerr Farm incident (*see, e.g.*, Romanak et al. (2013) https://www.sciencedirect.com/science/article/pii/S1876610213005699). 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 CO_2. 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 the 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 establishing these measurements as a snapshot at a certain period of time.[4] Tasks to facilitate process-based monitoring may include: 1) base characterization: measure ratios of gases (N, CO_2, O_2, CH_4) in ambient atmosphere, soils, AZMI; 2) develop workplan and timeframe for collecting samples; 3) attribution strategy (*see* ARB presentation by K. Romanak). Strategies should also take into account soil gas trends related to climate change over the requisite monitoring period.

V. Dissipation interval.

Dissipation interval, defined at (44), is an approach recommended in the 2017 white paper prepared at the request of the CARB by Lawrence Berkeley National Laboratory (LBNL). While the LBNL provides potentially useful criteria for application in certain parts of California, the approach has the following fundamental flaws when utilized as a general global approach:

1. 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 clear zones may lead to inaccurate geologic section descriptions.
2. 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 storage complex is demonstrably secure for permanent storage (e.g., reservoirs of the Permian Basin capped with salts).
3. A storage complex should be defined as a sequence of rocks that will contain CO_2 permanently, and the pressure dissipation interval, if present, is an asset.
4. A pressure dissipation interval could be used as a primary storage reservoir given that, by definition, that interval must be overlain by a robust seal.
5. The LBNL approach ignores that projects that qualify for the LCFS may be in other states. Dissipation interval (also AZMI) may be a positive qualifying attribute for monitoring and as a secondary storage compartment above the primary seal, but this attribute should *not* be required. Applying the LBNL approach globally could eliminate many secure sites.

Our recommendation is that ARB eliminate "dissipation interval" at definition (106) (a) as integral to storage complex and as a requirement at 2.1 (a)(4) and (5). Instead we suggest it can remain in the Protocol as an optional feature (e.g. as required in the storage complex geologic description in 2.3 (C)(3)(c)(5)) that could provide lower risk in some projects. Moreover, the interval, if present, may be useful for above – zone monitoring or mitigation – if it is not being considered as a primary storage zone.

VI. Seal Concept and Testing Requirement.

It is incorrect to define a seal strictly in the context of San Joaquin Valley geology that is characterized by a thick sequence of shale overlying the potential saline reservoir sequence (that furthermore must be tested for its capillary entry pressure and ductility). We recommend that CARB broaden its concept of a seal to include a sequence of rocks (confining system) with the demonstrated ability to secure CO_2 permanently (meaning on a geologic time scale). A sealing/trapping sequence need not be narrowly defined as a shale as a result of the testing requirement, (e.g evaporites, carbonates, etc). It is acceptable to keep such types of tests as an option in the Protocol, but we recommend that CARB eliminate these tests as fundamental *requirements* in the it.

VII. Developing a Performance-Based Post-Injection Monitoring Plan.

CATF strongly supports the inclusion of CCS within the LCFS regulation. The proposed Protocol requires all projects, irrespective of storage site characteristics or risk profile, to perform post-injection field monitoring for a minimum of 100 years to demonstrate permanent sequestration of CO_2. The Protocol defines "Permanent sequestration" or "permanence," to mean that "sequestered CO_2 will remain within the storage complex for at least 100 years"[5] Regarding the issue of permanence, CATF would emphasize that in order to reverse climate change, CO_2 that is captured and stored must remain sequestered permanently for much longer timeframes than 100 years. On post-injection monitoring requirements, CATF proposes that CARB develop a performance-based approach that will support the development and operation of CCS projects that will ensure secure sequestration of CO_2 on a geological time scale.

In a performance-based approach, storage security is a function of the quality of the geologic storage site, which is a product of the site selection process, the design of the injection, and the tailoring the monitoring and verification methods to the leakage vulnerabilities, using tools that can detect CO_2 in the project environment over the desired timeframe. For the practical purposes of accounting, demonstrating that stored CO_2 has achieved an equilibrium state with the host rock, such that it will not migrate out of the prequalified volume defined as the storage complex, is the goal of the Protocol. For storage in the deep subsurface, monitoring at the surface for 100 years has minimal value. Demonstration of permanence can be accomplished with highest certainty by combining analyzed plume monitoring data collected in the subsurface, and using matched models to demonstrate a robust trend in CO_2 stability.

The proposed method of post injection monitoring using CO_2 concentration in the soil gas is not reliable. Robust scientific research on the ability of baseline soil gas methods to detect leakage, suggests that the use of soil gas monitoring is fraught with uncertainty. In some cases of known leakage, nothing is detected in the soil; in other cases an observed change in CO_2 concentration is

[5] California Air Resources Board, Appendix B – Attachment 1: Carbon Capture And Sequestration Protocol Under The Low Carbon Fuel Standard, at page 17, *available at:* https://www.arb.ca.gov/regact/2018/lcfs18/appb.pdf

related to the ecosystem and unrelated to the injected CO_2. Furthermore, location and placement of instrumentation is tricky and must be designed to monitor areas with best chance of detection. As an example, at Aliso Canyon, leakage from the subsurface blowout manifested itself at the surface at a distance from the wellhead, at the bottom of the hillside, such that a monitor near the wellhead may have not detected the blow-out early. Critically, if leakage is detected in soils it is too late to mitigate; whereas subsurface detection methods would in many cases allow prevention of significant leakage.

In CATF's comments,[6] submitted on February 1, 2018, we provide legal reasons for why 100 years of monitoring required in the forest offset protocol *does not* necessitate requiring comparable monitoring techniques and methods under the CCS protocol. Permanence in geologic settings is fundamentally different than the timber harvesting risk in forestry. CO_2 stored in mile-deep reservoirs is covered by a thick overburden of rock, typically very impermeable. Vertical migration, if pathways are present, other than through well penetrations, will take much longer timeframes. Failing to recognize these differences and failing to tailor the Protocol to the factors relevant to geologic sequestration would be unreasonable and does not fulfill CARB's fundamental objective of sequestration permanence.[7]

This being said, and despite our objection to what we view as some overly rigid 100 year monitoring requirements, we have endeavored in our comments and proposed language to make judicious recommendations to make the rule more performance-based, within the confines of the 100 year requirement. If CARB wishes to retain the 100-year post injection monitoring requirement in the Protocol then CATF would urge CARB to make changes to the regulatory language as described below that preserve CARB's authority to impose various conditions but lessen the list of mandatory monitoring provisions applicable to all projects. The specific changes have been added as redline comments in Appendix A.

Our recommendations introduce several additional rule components that will facilitate the development of the most technically sound CCS projects and reduce obligatory monitoring not tailored to the risk profile of a particular project. We are confident that these approaches will enable performance-based monitoring and financial responsibilities throughout the life of CCS projects and the permanence period.

1. We recommend authorizing the complete transfer of project responsibilities including the Permanence Certification from a project operator to a third-party subject to Executive Officer approval. *See* redline recommendation in section C.1.2 in Appendix A. Long term, public entities will likely be established to manage carbon sequestration sites in the most secure and efficient manner given the strategies and technologies available in the future.

2. The Protocol should more clearly delineate the responsibilities for the different phases of the project. The current protocol contains a section on Injection Monitoring Requirements at C.4 but the Testing and Monitoring provision expands the scope of testing and monitoring requirements under this section to the "post-injection site care period" at C.4.1(a). We recommend removing this ambiguity by more clearly limiting this Testing and Monitoring

[6] Clean Air Task Force (CATF), Stakeholder letter in response to LCFS workshop Nov. 6, 2018 (Feb. 1, 2018), *available at:* https://www.arb.ca.gov/fuels/lcfs/workshops/02012018_catf.pdf.
[7] *Comms. for a Better Env't v. Cal. Resources Agency*, 103 Cal. App. 4th 98, 109 (2002)

provision at C.4.1(a) to the "active life of the CCS project" which is the injection period. *See* redline in Appendix A.

3. Post-injection monitoring obligations are best addressed in the section entitled Post-Injection Site Care and Site Closure at C.5.2. The Protocol already requires and enables a thorough review of the Post-Injection Site Care and Site Closure Plan under C.5.3. This comprehensive review should be based on the best available science at the time of the review, and would reference the project's historical performance including regulatory compliance, technical performance, and all other project components. At the conclusion of the review, the Post-Injection Site Care and Site Closure Plan will establish the monitoring obligations and financial responsibilities of the project for the remainder of the 100- year period. Our recommended changes to C.5.2(b) (Post-injection site care and monitoring) have been crafted to empower the Executive Officer with full authority to impose all necessary obligations to ensure permanence but also to enable the Executive Officer to not be required to impose standardized monitoring on all projects. *See* redline in Appendix A.

4. On issues of Financial Responsibility found in C.7, we find the Protocol to be unduly rigid in some respects. Overall, the commencement of the project is the vantage point utilized for assessing the necessary resources. We understand that the need for this approach during the period of initial review and approval of the Permanence Certification. However, after the CCS project has an established operational history and compliance record, we think that the risk assessment should be revisited. We have several specific recommendations in this regard.

    a. Regarding the risk of CO_2 leakage, the current language is insufficiently precise regarding the nature of the risk that must be covered by the financial responsibility instruments. We have suggested specific language to define this more clearly in the first sentence of C.7(a)(3).
    b. Regarding the risk of atmospheric CO_2 leakage, we recommend that the credits that a project has deposited into the buffer pool of LCFS credits during the course of the injection period be taken into account. Using this approach, the account balance for a project would be calculated after the injection period using a new section B.3(e). The proposed approach would recognize all credits contributed and adjust the balance by any leakage that has occurred during the CCS project's active life.
    c. Regarding financial responsibility in the post injection period, we are recommending that CARB recognize the buffer pool contributions that a specific project has made during its active life as a qualifying financial responsibility instrument under C.7(a)3. This financial responsibility instrument could only be used to address the financial risk of atmospheric CO_2 leakage post injection.
    d. We think that the Protocol would benefit from the establishment of a methodology to calculate the risk of atmospheric leakage of CO_2 for Financial Responsibility purposes. We are recommending that CARB utilize the same risk matrix approach that already exists in Table G.1 of Appendix G but apply it to the Financial responsibility section via C.7(a)(3). Post-injection, we recommend that this risk be recalculated based on project performance and compliance history. We recommend a new risk matrix approach as proposed in a new Table G.3.

VIII. Conclusion

In conclusion, CATF urges CARB to more broadly implement a performance-based monitoring approach and to integrate the other specific recommendations we have submitted to the record. Our recommendation aligns with the California Legislature's direction to "substitute[e] performance standards for prescriptive standards wherever performance standards can be reasonably expected to be as effective and less burdensome."[8]

We look forward to continuing our work with CARB on the Protocol and appreciate the ongoing opportunity to provide feedback and recommendations. We also look forward to the development of CCS projects that meet the final Protocol's requirements, and to the continued refinement of the regulatory structure based on real world experience, science and technology.

Respectfully,

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[8] CA Govt. Code § 11340.1(a).

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) 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).

(f) 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 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 Permanence Certification or a revised Permanence Certification.

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

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(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 evaluation required under subsection C.2.4.1;

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(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 reevaluation performed under subsection C.2.4.4; and

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(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 Storage Complex reevaluation; or

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(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 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 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

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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.

(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 is no longer increasing (or is decreasing) and conforms to model predictions pursuant to subsection C.2.4.1, and until CARB agrees a substantial trend in plume stabilization has been demonstrated to the satisfaction of the Executive Officer.

(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) If required by the Post-Injection Site Care and Site Closure Plan, the CCS Project Operator must in conformance with the specified timeline:

1. Conduct 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 Storage Complex delineation pursuant to subsection C.2.4 to determine if any corrective action is necessary until a trend in CO_2 plume stability has been demonstrated.

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 stabilization trend is demonstrated to the satisfaction of the Executive Officer.

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(E) Once the trend in CO_2 plume stability has been demonstrated, all CCS project wells may be plugged and 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.

(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.

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<#>Visual inspection of the wellhead and the land surface within a 100 ft radius of the wellhead or well pad.

(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 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).

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(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 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. 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 Storage Complex, plugging the well(s), post-injection site care and site closure, and emergency and remedial response.

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(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 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.

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(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 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

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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 Risk of Atmospheric Leakage and Contribution to the LCFS Buffer Account

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. CARB maintains LCFS Buffer Accounts 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.

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(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, to recalculate it every time the CCS project undergoes verification, and to recalculate it after injection has terminated and the Post-Injection Site Care and Site Closure Plan has been approved or re-affirmed.

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(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 during injection phase of project 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	

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)

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, and proven compliance history of highly competent management control of CCS project during injection phase.	0%
	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 sequestration of CO_2. Data quality management has been sufficient to support quantification and verification of CO_2 sequestered with no indications of significant site risk.	0%

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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 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.	1% 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.	0%
	Higher Well Integrity Risk: The CCS project has wells that do not meet USEPA class VI well or equivalent requirements or has indications of unmitigated well integrity issues during injection period	3%

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

$$CCS\ Project\ Risk\ Rating = 100\% - \left[\left(100\% - Risk_{Financial}\right) \times \left(100\% - Risk_{Social}\right) \times \left(100\% - Risk_{Management}\right) \times \left(100\% - Risk_{Site}\right) \times \left(100\% - Risk_{Well\ Integrity}\right)\right] \tag{G.1}$$