Mr. Samuel Wade
Chief, Transportation Fuels Branch
Industrial Strategies Division
California Air Resources Board
1001 I Street
P.O. Box 2815
Sacramento, CA 95812

December 4th, 2017

Re: Comments on Draft CCS Accounting and Permanence Protocol and on Draft Regulatory Amendments to the Low Carbon Fuel Standard as these pertain to CCS technology

https://www.arb.ca.gov/fuels/lcfs/workshops/feedback.htm#11062017

Dear Mr. Wade:

Our coalition represents a diverse group comprised of industrial sources of greenhouse gases (GHGs), potential CCS project developers, technology providers, academics, and non-governmental organizations (NGOs). We offer the comments below on the Accounting and Permanence Protocol for CCS, as well as the portions of the Draft Regulatory Amendments to the Low Carbon Fuel Standard that are relevant to CCS technology as a compilation of views from our varied perspectives.

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 (ARB) 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 production of lower carbonintensity fuels used in the state. It is worth underlining ARB's dual goals as we perceive them: to allow for CCS technology to make meaningful contributions to emission reductions, and also to make sure that this is done in a manner that is environmentally sound.

The proposed CCS Protocol represents likely the most comprehensive effort to date on CCS regulation. 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]

We believe that the draft Protocol contains many sound elements, but also that several changes are critically needed if the protocol is to meet its dual objectives of protecting the local environment and resulting in meaningful climate mitigation. We believe those changes to be possible within the architecture of the proposed Protocol. Some highlights of our recommendations include:

- **Site-specific performance standards** are, in many cases, more appropriate for dealing with the variety and complexity of geological formations in which CO_2 might be stored than prescribing specific technologies and work practices that may be less effective and/or introduce additional risks. Site specific performance standards are particularly critical in defining the following critical terms: area of review, sequestration zone, primary sequestration zone, storage complex, confining system, primary confining zone, injection zone.
- **Pressure front** – A CO_2 injection pressure front will far exceed that of the actual CO_2 plume, but it should be recognized that the pressure over original pressure will diminish with distance to a level that is inconsequential in terms of containment. Monitoring infinitesimal increases in pressure would also be impractical in terms of logistics (wells, land access to huge areas).
- **Use or seismic surveys, soil gas and surface-monitoring technologies** – Abundant field cases illustrate that these techniques are not always appropriate or effective in monitoring the injected CO_2 and flux from the subsurface. Consideration of site-specific factors and a rigorous screening process should lead to the selection of the most appropriate and effective monitoring tools in each case.
- **Post injection site care (PISC)** – The proposed schedule and prescribed activities for PISC monitoring is inconsistent with the objective of establishing storage "permanence" a high degree of confidence. A more rigorous approach is to use the right tools early on and to adjust the strategy based on the abundant operational monitoring data. The appropriate period over which to monitor should be adjusted based on the track record of the operator and the site. In order to ensure proper stewardship of sites and avoid gaps in monitoring duties in the future, funds should be collected upfront for the purpose and the duty transferred to a designated entity after a period of time.
- **CO_2-EOR and out-of-state projects** – Enhanced oil recovery projects that use CO_2 and projects in other jurisdictions are likely to be among the earliest applicants for credits under the proposed Protocol and LCFS regulatory changes. We are not advocating for more lenient or favorable treatment for such projects. However, we want to ensure that projects also governed by other

[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.

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.

Below we present detailed comments on the Accounting and Permanence Protocol for CCS first, followed by comments on the Draft LCFS Regulatory Text (Sep.22, 2017 Update), which include the issues highlighted above, along with several others. We thank ARB staff for its continued work on this important topic, and look forward to working together during the final stages of the process.

Respectfully submitted,

Jeffrey Bobeck, Policy Lead, Americas Region, Global Carbon Capture and Storage Institute

Jeffrey D. Brown, Research Fellow, Steyer-Taylor Center for Energy Policy and Finance, Stanford

University[2]

Al Collins, Sr. Director – Regulatory Affairs, Occidental Petroleum Corporation

Paul J. Deiro, Vice President, Government Affairs, California Resources Corporation

S. Julio Friedmann, CEO, Carbon Wrangler, LLC

Susan D. Hovorka, University of Texas at Austin

Eric Mork, EBR Development, LLC

Deepika Nagabhushan, Energy Policy Associate, Clean Air Task Force

Bob Perciasepe, President, Center for Climate and Energy Solutions

George Peridas, Senior Scientist, Natural Resources Defense Council

Chris Rathbun, CCS Manager, Shell

Michael J. Rubio, Manager, California State Government Affairs, Chevron Corporation

Greg Thompson, CEO, White Energy

Tom Willis, CEO, Conestoga Energy Partners, LLC

[2] The views of the researcher do not necessarily represent the views of Stanford University.

Definitions [Section A, §2]

We offer some comments and suggestions on the proposed definitions below.

Area of review, sequestration zone, primary sequestration zone, storage complex, confining system, primary confining zone, injection zone

These are critical components to the protocol that need additional work in both the definition and conceptualization to be clear, technically correct, assure storage permanence, and avoid eliminating viable sites by overly restrictive language. There are inconsistent and confusing uses in the document.

We recommend that the definitions be performance based. Examples of performance based definitions that include and integrate the terms are

> "The storage complex is the three-dimensional subsurface volume that is characterized, modified by corrective actions, and monitored so that the project is able to meet the permanence requirements for carbon sequestration. The storage complex includes the injection zone (in which the CO_2 is emplaced), a sequestration volume[3] which is expected to contain the CO_2, and overlying and possibly underlying geologic formations that are required to provide assurance of storage. The storage complex must include a confining system that retards vertical migration of CO_2, and may include dissipation zone(s) and additional confining zone(s) to increase storage security and reduce other risks. The storage complex must extend laterally over the volume from which CO_2 (as a free or dissolved phase) could escape from storage in the subsurface if a permeable pathway exists."
>
> "Area of review is the map outline of the area over which all possible permeable pathways (wells, natural or engineered faults, fractures or other transmissive zones) must be evaluated and either shown to be non-transmissive or remediated."

Area of review for dissolved CO_2

This term does not seem to be used, as it is covered by the definition of AOR.

Capillary entry-pressure

The definition restricted to a confining layer is inaccurate. Capillary entry pressure is relevant to flow in reservoir also. We recommend the following modification:

---

[3] The term "sequestration zone" used extensively in this document is not widely used in the CCS literature and seems to be used in two ways in the document. In the definitions, "sequestration zone" (meaning 1) is the subsurface volume of sufficient size to accept the CO_2, i.e. the target zone on which capacity was assessed. It is likely that wells are designed to access this volume efficiently. Elsewhere in the document, the term "sequestration zone" (meaning 2) is the area of elevated pressure and matches to the AOR. However, to reduce risk of leakage and of project non-conformance, this second use should be a different, vertically and horizontally larger "storage complex" which should be qualified in terms of being characterized, modified by corrective action, and monitored. Elevated pressure and some CO_2 migration would be acceptable in any part of the storage complex. If this definition set was used, many but not all of the "sequestration zone" terms in the text would be changed to "storage complex".

> “Capillary entry-pressure” means the pressure that a non-wetting fluid (e.g. CO_2) must overcome to displace water held tightly by capillary forces in the pores of a rock or sediment ~~of a confining layer~~.

CO_2 injection

“In a supercritical state” is over- specific and leaves out parts of the normal injection processes. The injected CO_2 may be gas, liquid, or supercritical at wellhead, depending on temperature and pressure. CO_2 may change state as it moves down the well, depending on temperature and pressure in the well. Temperature and pressure are related to many factors, such as pressure in the reservoir, column heights of the fluids in the well, rock temperature outside the well, and rate of injection. It is possible that CO_2 at the well perforations entering into a low-pressure reservoir might initially be gas or liquid. These variants are usually considered acceptable and should be covered by the term CO_2 injection. We recommend the following modification:

> “CO_2 injection” means is the process of injecting CO_2 ~~in a supercritical state~~ into geologic reservoirs.

CO_2 recycling

The following definition is currently proposed:

> “CO_2 recycling” means the process that separates CO_2 from produced oil, water, and gas for re-injection in the subsurface or transfer off-site.

This definition mismatches with “recycled CO_2” in the definitions and Protocol text. In plain English but also in the EOR industry, “separation” and recycling have distinct and different meanings. Industry practices are variable and industry also uses variable terms in this area, “gas processing” also being a common one. Both the terms “CO_2 separation” and “gas processing” have multiple applications in CCS context, so we suggest that ARB specify oil/water/gas separation or oil/water/ CO_2/hydrocarbon gas separation in the definition and text.

Depleted oil and gas reservoirs

The phrase “no recoverable oil or gas” comingles technical and economic considerations and should be avoided for clarity. We suggest the following modification:

> “Depleted oil and gas reservoirs” means the reservoirs which do not currently produce oil or gas, and are considered to have no economically recoverable oil or gas with current technology, ~~and furthermore will not produce oil or gas upon~~ without a new production phase (including CO_2 injection) or technology.

Deviated well
All wells have some accidental deviation from zero. Bottom hole is normally not exactly below the wellhead, and the drillers may have to do some corrections if the well starts to deviate much from vertical. Drillers usually run a deviation log to find out how close to vertical a well is. We suggest the following modification:

> "Deviated well" means a well that is not drilled vertically for its whole length, or a well with an inclination <u>designed to be</u> other than zero degrees from vertical.

Dissipation interval
This concept of attenuation of risk across the confining system is useful and well-documented in the literature. However, the reference to "any potential overpressure" could mean infinitesimal, and may not be usable. We suggest the following modification:

> "Dissipation interval" is a stratigraphic interval with hydrogeologic properties sufficient ~~to fully dissipate any potential overpressure~~ to <u>attenuate</u> pressure increase created by CO_2 or formation fluid migration along an unidentified leakage pathway through the confining layer.

Entrained CO_2
Use of the term "recycling" is not clear.

> "Entrained CO_2" means CO_2 that remains in water, oil, or natural gas after CO_2 ~~recycling~~ <u>oil/water/gas separation</u>.

Hydraulic conductivity
Non-Darcy flow, such as fracture flow, should be included in hydraulic conductivity definition for storage. We suggest the following modification:

> "Hydraulic conductivity" is a measure of a material's capacity to transmit a fluid. It is defined as a constant of proportionality relating the ~~specific~~ discharge of a ~~porous~~ medium under a unit hydraulic gradient ~~in Darcy's law~~.

Hydraulic head
Without permeability, no flow will occur. We suggest the following modification:

> "Hydraulic head" is the force per unit area exerted by a column of liquid at a height above a depth and pressure of interest. <u>If connected by permeable flow paths</u> ~~In general,~~ fluids flow down a hydraulic gradient, from points of higher hydraulic head to points of lower hydraulic head.

Hydrostatic stress
Term is defined but is not used anywhere in the Protocol.

Induced seismicity

The following definition is currently used:

> "Induced seismicity" means earthquakes that are caused by human activity (e.g. wastewater injection).

This definition is only used once in the document and is not sufficiently nuanced for such a high-profile topic. Almost all injection will cause or trigger some seismicity of very small magnitude. The threshold of tolerance for this perturbation is quite significant for viability in CCS, and should be incorporated in the definition. The draft Protocol uses magnitude 2.7 in §2.4.4.1(f)(1).

Injection and storage site

This definition has implications where multiple uses (and ownership) of the subsurface are involved, as in most hydrocarbon-productive basins or mined lands. It is unclear what the intended meaning is: from reservoir to surface, or from surface to center of the earth, does it include surface infrastructure? We recommend linking this to other terms such as "storage complex".

Injectivity test

The detailed definition mismatches with common definitions and with the Protocol text. Is this term needed in the definitions since a performance based definition is provided in the text?

Intrinsic permeability

This term is not used in the main text, and adds confusion to definition of "permeability".

Isochore map

This term seems superfluous to the more common "isopach map", as the difference between the two is not significant except when dip is very high.

Multiphase flow

The relevant definition should include two immiscible phases :CO_2 (as a gas, a liquid, or supercritical), and brine or oil.

Porosity

We suggest defining porosity as a volume percentage.

Pressure front

The term "pressure front" is used extensively through the document and should be defined with care using performance-based terms, as this definition has profound implications for the viability of storage. The general technical meaning is that used by Vasco (2011), a derivative of pressure change. However, this does not seem to be what is under consideration here. The proposed definition presents a problem, in that any injection will create "a pressure differential". In most cases, the area of slightly elevated pressure extends over very large areas that could include the greater part of an entire basin.

Some qualifier or magnitude threshold is needed. UIC rules often use endangerment as a criterion, as in the pressure capable of lifting brine such that the risk to fresh water is increased. Note that in many regions like California with topographic changes, artesian pressure in confined saline aquifers exists under ambient conditions, such that they would flow out of the zone naturally. We note that the use of the term in EPA Class VI regulations appears to have a flaw, in that the pressure front criterion appears to include basin scale-endangerment in artesian basins.

ARB should incorporate a relevant threshold. See also following comments on Area of Review.

Recycled CO_2

Many different separation and recycling processes are used. For example, all the gas (CO_2 and hydrocarbon gas) may be reinjected, or they may be separated and the hydrocarbon gas sold or combusted. We suggest the following modification:

> "Recycled CO_2" means CO_2 that was separated from oil, water ~~and~~ or non-CO_2 gases and reinjected back into a reservoir.

Seepage velocity

This artificial velocity is defined and used in text but the modeled and actual fluid velocity (which may be relevant to some monitoring plans) will be much greater, as the relevant thickness accessed by CO_2 is much smaller than L. It is misleading to use this formulation. "Flux" would also be a better term.

Storage complex

We suggest the following modification:

> "Storage complex" means the storage (sequestration) zone and surrounding geological domain, and is composed of the sequestration zone, confining layer, and any dissipation intervals needed to dissipate excess pressure above and/or below the storage zone.

Transmissive fault or fracture

We suggest the following modification:

> "Transmissive fault or fracture" means a fault or fracture that has sufficient permeability and vertical extent to allow fluids to move laterally or vertically along the fault or fracture, or within an associated damaged zone ~~between formations.~~

Vertical stress

The term used in the text is effective vertical stress, which considers pore pressure. We suggest linking to the definitions of lithostatic and hydrostatic stress, and the following modification:

"Vertical stress" means the force per unit area ~~weight of the overlying material~~ imposed on a layer of rock. Vertical stress is the combined stress due to the total weight of rock and interstitial fluids above a specified depth.

Wellbore

The terms "well" and "borehole" are also used and should be made consistent or defined as synonyms in this document.

Accounting methodology [Appendix A; and Section B, §2][4]

The prospective CCS project operators in our group believe that there are methods to account for saline CO_2 storage which are less complicated to calculate than what ARB has proposed in Appendix A. Under this alternative method, all relevant data required to quantify the GHG reduction benefit achieved by CCS in a pure storage operation for both the LCFS and Cap & Trade programs is provided by three main data points:

- The amount of CO_2 received at the inlet of the capture facility (A)
- The amount of CO_2 generated in association with the energy utilized in the capture and compression operations (B); and
- The amount of CO_2 delivered to the wellhead or field manifold for injection (C) as measured by a meter.

The quantity of CO_2 stored is represented by (C). The net quantity stored is represented by (C) minus (B). The un-stored (i.e. emitted) CO_2 from the regulated facility is represented by (A) minus (C) plus any emissions that were not routed to the capture facility.

Under this approach, it is unnecessary to estimate or measure fugitive or vented emissions in the capture and transport operations through equipment counts or leak detection programs. In the event CO_2 is fed into a common pipeline for storage by multiple regulated facilities, metering the CO_2 streams as they feed into the CO_2 mainline provides a mechanism for the transport and storage operator to pro-rate stored emissions to individual shippers. Any CO_2 released downstream of the injection meter can be calculated and deducted from the amount stored. Further, because the CO_2 will be in dense phase at its delivery point in the field, any leakage downstream of the injection meter will be readily detectable and can be estimated and deducted from the stored quantity.

We recommend that ARB evaluate whether the use of the methodology described above provides a simpler alternative for calculating the greenhouse gas emission reduction without introducing any errors or missing out potential emission terms.

Consistent with this approach, we ask ARB to also consider the following points under Section A, §2:

[4] NRDC has not evaluated the validity of the approach proposed here, and is neither recommending nor opposing its adoption. We support simplicity, provided the result is the same and that no fugitive emission or other terms are overlooked in this proposed approach.

- Equation 1 in this section defines the GHG reduction as the difference between CO_2 injected ($CO_{2\ injected}$) and the GHG emissions resulting from the project ($GHG_{project}$). Since $CO_{2\ injected}$ is measured at the point of injection, is it necessary to include fugitive and venting emissions that occur upstream of injection in the $GHG_{project}$ value?
- Equations 3 and 4 include fugitive and venting emissions from CO_2 capture and transport into $GHG_{project}$. As these emissions would occur upstream of CO_2 injection, should the $CO_{2\ vent}$ and $CO_{2\ fugitive}$ terms be included in equations 3 and 4?

Equations 3 and 5, which establish the GHG emissions related to CO_2 capture and injection, include a term for GHG emissions from fuel combustion ($GHG_{combustion}$). Any combustion sources located at a facility capturing or injecting CO_2 may elect to capture the CO_2 from these sources as well. Should it be stated that the $GHG_{combustion}$ value is net of any resulting emissions which are themselves captured?

Land use [Section B, §2.2]

In the "Accounting Requirements for CCS Projects Under LCFS" of the proposed Accounting and Permanence Protocol for Carbon Capture and Geologic Sequestration under Low Carbon Fuel Standard documents released by CARB two equations reference Direct Land Use Change (dLUC) as part of the accounting for GHG reduction. These are for CO_2 transport, injection and storage. We agree that certain projects may have dLUC and associated GHG emissions. ARB should be clear, however, to separate existing infrastructure and land disturbances from new and additional disturbances from a CCS project under the LCFS and consider establishing a de minimis threshold.

For example, EOR operations have been in existence for several decades in in many regions and transportation pipelines have been developed before the genesis of the Protocol. Along with these transportation pipelines, wells have been in use and have been developed for production in their inceptions, and some are to be or have been converted to injection wells. In both cases the land is no longer virgin land. In the case of converting depleted oil and gas fields into storage sites, some of the wells that would be utilized for injection will have already been drilled. The gathering systems that were used to transport natural gas production can often be repurposed for CO_2 transportation.

ARB should implement dLUC calculations in a way that takes into account existing infrastructure and existing land disturbance as part of the baseline.

Performance-based criteria for selecting the best technology or method [Section C]

We note that in several places, ARB has mandated a list of specific technologies or methods for consideration, but allows for the use of alternatives provided equivalent or better performance is demonstrated to, and approved by, the Executive Officer:

- §2.3.1(l)(4)
- §3.2(a)(5)
- §4.3(b)(2)

- §4.3.2.1(d)(4)
- §4.3.2.1(c)(4)
- §4.3.2.2.2(i)(7)
- §4.3.2.2.2(j)(4)

We support this approach as it embodies the site-specific nature of designing and operating the best projects, and does not lock in weaknesses of specific technologies or introduce unnecessary risks. We do recognize, however, that in some cases the best technology or method may indeed be one of those listed, and recommend that the Executive Officer discuss the choice of proposed methods with operators and ensure equivalent or better performance in all cases.

Opportunity for public input where Executive Officer discretion is exercised [Section C]

As per the previous comment, there are several instances in our comments where we recommend that the Executive Officer have the discretion to approve a particular method or course of action provided that it is equivalent or better than a specific one listed in the Protocol. In such cases, ARB should provide sufficient public notice and invite public input through comments or workshops.

Permanence requirements for operating EOR projects [Section C]

The requirements discussed here in relation to EOR projects are limited to those relevant for demonstrating CO_2 storage permanence. We do not discuss additionality or any other issues relevant to eligibility for LCFS credits for operating EOR projects.

The proposed Permanence Protocol has requirements that could inadvertently preclude CO_2-EOR from qualifying with the Protocol's permanence provisions,[5] and should be modified to recognize the inherent differences, and thus areas of focus in the protocol, for saline and EOR in all relevant areas. Furthermore, the draft Protocol is also missing some key elements that would allow assurance of permanence to be effectively assessed in the CO_2-EOR context. 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 used in EOR 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.

We want to underline that we are not advocating for more lenient or favorable treatment for EOR projects. 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.

[5] Occidental believes that the ability to comply with containment criteria in the CO_2 EOR context has been affirmed by EPA's approval (under the Clean Air Act) of a Subpart RR application for its Wasson (Denver Unit) and Hobbs fields.

Regarding the practical business and assurance aspects of CO_2 EOR, we outline below general principles that we support followed by comments and recommendations on specific line-items in the Protocol.

General Principles

Wells – We support being able to reuse wells if tests demonstrate their integrity to an equivalent or higher level than required in the Protocol. Equivalent or better remediation, surveillance and testing practices should be considered. We recognize that previously plugged and abandoned wells may comprise a containment risk, particularly those that are older and/or poorly documented. A risk-based evaluation process should be employed to assess potential failure of such wells to prioritize those that will have to be reentered and re-plugged/abandoned.

Characterization and AOR – By virtue of multiple decades of operation, CO_2 EOR fields are effectively characterized in terms of reservoir stratigraphy and petrophysics. Seal and trap characteristics have historically not been characterized systematically but their integrity is established by their ability to accumulate hydrocarbons and is maintained by active pressure management. Compared to CO_2 saline storage projects, AOR is therefore largely constrained areally to the structure that allowed hydrocarbons to accumulate. There are exceptions, however, most notably potential cases of off lease migration (whether vertical or lateral). This could be managed through evaluating the mechanism, quantifying the flux (for credit purposes) and ultimately through corrective action.

Monitoring – The key consideration for monitoring CO_2-EOR fields should be the quality of historical and current pressure maintenance (supported by mass balance data, fluid analyses, Hall plots, etc.) Please also refer to our comments on repeat 3D seismic monitoring.

Closure – The mobility and state of CO_2 at the end of a CO_2-EOR project is substantially different from that of saline CO_2 storage. Whereas end of injection pressure may exceed original pressure, it will be below fracture gradient and will not, under ordinary circumstances, move laterally over time due to de facto AOR constraints (discussed above). For CO_2-EOR projects that experienced few or no material containment issues during operations, the post-injection monitoring period to establish "plume stability" should be brief and focused on addressing remaining, plausible risks.

Protocol Line Items

p. 30, "CO_2 vented from the last batch of crude...". This should be phrased more generally, and included in a discussion on closure. Experience at the end of CO_2 EOR is limited, however, some oil remains in the ground. Future operators may attempt to extract remaining oil by any number of techniques. Protocol should make clear that if any CO_2 is released in the late stages of CO_2 EOR, it should be included in accounting. Note that operations are complex, water-flood and CO_2 EOR may be applied to different patterns of the same field.

p. 43, (8)(C) A The requirement for hydrocarbon composition in CO_2-EOR and depleted reservoirs should be made performance based, for example, "compositional data needed for modeling fluid interactions should be collected".

p. 44, The requirement for coring should be balanced against the damage that coring can do to the borehole (e.g. create washouts in weak formations). Coring should be required only if adequate data are not available. Coring is not a best practice on every well. Fluid sampling should not be needed in a mature reservoir at this stage.

p. 46, Downhole conditions listed in (g) cannot be collected before well completion because the well should be filled with drilling mud until casing is completed. Note that in depleted reservoirs, the hydrocarbons cannot be produced, ordinary fluid sampling is not useful. A plan to obtain fluid characterization to support modeling may require flexibility, including working with data collected during earlier stages of the flood or specialized coring.

p.50-54, This modeling section is poorly conceptualized for CO_2 EOR. Modeling CO_2-EOR is very mature and known to be quite difficult and computationally expensive. The inputs, outputs, risk profile and opportunities are quite different from saline formations. Key elements:

A good reservoir model for EOR will include and be calibrated reasonably well using available data from past production. This is an opportunity to greatly improve the model over what is possible in a saline formation that has never been produced. Note that although history matching in this setting is mature, it is never perfect.

"Plume and pressure front" have little meaning in EOR. Each injection-production pattern has its own multi-pointed star shape of saturation and pressure. Often modeling for the field is approached at a pattern scale, and then upscaled.

Modeling CO_2-hydrocarbon interaction is very complex and is computationally intensive to model. Usually field surveillance is conducted with simpler models, such as injection-withdrawal ratios that accept the very dense data generated by an EOR operation. For example, each producer in the field provides a "monitoring point". The operator collects production data, often monthly, and then adjusts injection and production operations with high frequency to optimize production. Working all this in a geo-cellular model may be prohibitive.

p. 53, 2.4.2(c) states that "a single AOR modeling exercise may be conducted for all wells within a single GCS project at the discretion of the Executive Officer". All operations that impact pressure in the storage complex should be assessed in the model. If distant operations (e.g. recharge or production in a nearby field) have an impact on pressure they must be considered in model boundary condition construction. For CO2-EOR that all the injection and production wells that form the pattern flood must be included to assess risk management and monitoring. We suggest that ARB revise requirement to "the AOR modeling exercise must include all operations that impact fluid pressure in the storage complex."

p. 54, The corrective action plan seems to be missing several CO_2-EOR specific (non-abandoned) well issues:

- All existing wells should be assessed to ensure qualification for CO_2 service. Categories of injection, production, monitoring, or TA are needed.

- Wells penetrating other parts of the storage complex should be inventoried and their condition assessed.
- Risk of out-of-pattern migration to adjacent production (not on recycle) should be managed.

p. 59, 2.4.3.1 The statement “to the extent known” is very important, as we rarely see this complete data on any well.

p. 63, In addition to the general limitations to soil gas measurements, special difficulties may exist in CO_2 EOR settings.

- It is common for geologic hydrocarbon seepage followed by microbial process to create high CO_2 “bulls’ eyes” naturally over oilfields. This is a historic exploration technique.
- Past modification of the land surface, including spills and remediated past infrastructure creates high and systematically trending CO_2 concentrations.
- Remediation and improvement of the site as part of preparation for CO_2 EOR creates high and trending CO_2 changes. For example, improved drainage in roads and modern berming of infrastructure will change recharge mechanisms and may increase soil moisture and CO_2 production as a result of respiration.

p. 70, 3.3 (c) “no injectate other than CO_2 ...” this seems to bar injecting brine as part of water alternating gas (WAG) commonly used in CO_2 EOR for conformance control. Other additives are in development to improve EOR, e.g. foam.

p. 73, (10) Surface air monitoring may be problematic in an oilfield setting if any combustion fired motors are in use for production.

p. 74, 4.2(c)(2) See relevant comments in Mechanical Integrity Testing.

p. 87, 4.3.2.1 In addition to other limitations on reliance on seismic for plume tracking, the following special issues for CO_2 EOR are noted:

- CO_2 cannot be separated from methane gas using seismic techniques. Therefore, serious limitation in seismic imaging of CO_2 occur if the reservoir has methane in it.
- In CO_2 EOR, there is no mobile plume front. Each injector-producer pattern has its own plume front.

Also, there is no large area of elevated pressure, each producer creates a local pressure sink. It is not feasible to contour pressure within each pattern.

p.90, 4.3.2.3 requires downhole seismic monitoring at each injection well. In an EOR project with a large number of patterns, this is excessive and unnecessary. A well-designed array for locating events in the whole field will provide better information and would be preferred in a site with high seismic risk.

p. 95, CO_2-EOR plume migration in miscible floods may be less than in a saline context because the miscibility of CO_2 and oil may limits migration. However, it is reasonable to ask that a model showing stabilization be created to eliminate the following losses:

- CO_2 EOR stops but adjacent production continues, CO_2 and oil may be drawn to adjacent production and CO_2 could be released from the AOR, although it would be captured by the adjacent EOR operations.
- Engineered barriers such as production or water curtain are taken out of service, and the CO_2 distribution changes.

This is relevant in EOR if small changes will take the CO_2 into areas with unprepared wells.

Permanence requirements for operations outside California [Section C]

We understand the intent of the quantification methodology and permanence protocol to enable regulated entities in California and fuel suppliers outside of California to earn recognition for capture and stored CO_2 within the Low Carbon Fuel Standard. We are concerned that a strict, to-the-letter interpretation of the permanence terms in the protocol would preclude *any* CCS projects undertaken outside of California, where regulatory and legal frameworks may impose different terms and requirements. 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 a pragmatic approach that allows for functional equivalence to be the criterion by which the sufficiency of requirements from other jurisdictions are evaluated. 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.

We want to underline 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.

Area Of Review [Section C]

We support the dynamic determination and revision of the Area of Review as dictated by operational data, as opposed to the use of a fixed radius that has proven inadequate in practice.

The AOR Delineation using Computational Modeling Results [2.4.2(b)] applies a broader definition of the AOR than how it is formally defined in the document. An AOR that encompasses the "pressure front for the cumulative GCS project model", strictly interpreted to encompass infinitesimal increases in pressure, would impose unworkable requirements as this would represent an area defined by hundreds of miles in each direction (tens of thousands of square miles, or the greater part of entire basins). The risks associated with the overwhelming majority of the pressure front are very small. The majority of this area represents small fractional increases above hydrostatic (background) pressure. This means that defining a very large AOR over the pressure front has no material benefit to the project, the public, or the ecosystem.

<u>ARB should review the document to ensure that the definition and references to the pressure front specify it as being the area in which fluid-pressure increases are sufficient to drive CO_2 and formation fluids out of the storage complex</u>.

Third party review [Section C, §1.1.1]

We support the ARB's inclusion of a mutually agreed upon Third Party reviewer(s) to certify the accuracy, completeness and adequacy of the applicant's assessment data, plans and risk assessment to ensure storage permanence. We encourage the ARB to consider a similar role for Third Party review in mediating:

- Operational variances from the QM where the applicant can demonstrate that an alternate (or new) technology or procedure can accomplish project objectives for ensuring storage permanence; and
- The evidentiary status of the CO_2 plume/pressure front at project closure and during the post closure site care periods and thus the scope and time frame for monitoring.

We also encourage ARB to develop a committee of reviewers expert in specific as well as multiple disciplines representing a range of institutions (industry, academia, national labs, NGOs).[6]

Requirement for a secondary sealing formation and a dissipation interval [Section C, §2.1(a)(5)]

Whereas a secondary reservoir and caprock set above the primary seal would be desirable both in terms of risk reduction but also for the purposes of "above-zone" monitoring, such a requirement could rule out good sequestration sites while narrowing selection to sub-optimal ones. For example, a thick, competent caprock overlying a high-capacity storage reservoir would be more secure than a lower

[6] Occidental does not support third party certification because ultimate approval of the application must always lie solely in the hands of the Executive Officer. However, there may very well be situations where the Executive Officer seeks outside expertise to advise and assist in their reviews and approvals. Occidental supports this type of regulatory assistance by contractors and consultants to CARB. Additionally, Occidental believes that the third party review at EOR fields is redundant and unnecessary given existing regulatory oversight from state and federal agencies for oil and gas operations and particularly those operations which monitor, report and verify CO_2 in accordance with 40 CFR §98.440-449 (Subpart RR) of the EPA's Greenhouse Gas Reporting Program.

capacity reservoir with multiple (stacked) caprocks. Among the storage sites with only one known containment layer are:

- The operating Sleipner project (Norwegian North Sea; 20 million tons stored since 1996); and
- The proposed White Rose project Bunter Sandstone (UK North Sea)[7].

Thick and/or geomechanically competent caprocks may be superior to multiple caprocks that may or may not possess such features. Although it is unclear whether apparent CO_2 entry into the In Salah injection project seal originated from an induced or pre-existing feature, the substantial thickness of the seal ensured that the overall containment system was secure.

To avoid situations where a high integrity storage system is excluded due to a prescriptive declaration of a minimum of one dissipation zone and containment layer, ARB should encourage applicants to propose sites that have a secondary containment zone, allowing the applicant to justify through rock stratigraphic and geomechanical analyses with accompanying risk analyses the selection of sites that does not have this feature. ARB should also consider the merits of a dissipation zone without a secondary sealing formation if it is demonstrated that in the unlikely event CO_2 migrates above the primary containment layer it could be dissipated (via capillary trapping and dissolution in brine) prior to reaching a protected feature (mineral, USDWs or atmosphere).

In addition, ARB should correct the definition of caprock for the dissipation interval, as the present wording implies that the secondary confinement unit is *below* this interval.

Risk assessment [Section C, §2.2]

We support the inclusion of a requirement to perform a site-based risk assessment [§2.2]. This is a necessary step for siting and operating a sound project, and forms the basis for numerous decisions thereafter.

Leakage detection limits and crediting [Section A, §2.2(e)]

ARB is proposing that the amount of CO_2 leaked "must be considered to be equal to the detection limit of the equipment used to detect leaks in the project's monitoring plan, absent any detected leaks" [§2.2(e)], citing conservatism as the sole justification for this approach. This is counter to the notion that CO_2 injected is CO_2 stored, unless shown otherwise. Absent an indication from the monitoring program or otherwise, none of the injected CO_2 can justifiably be deemed to have escaped to surface.

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. 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 ARB's faith in its own regulations. The proposed provision effectively assigns a probability of 1 to leakage.

[7] "K42: Storage Risk Assessment, Monitoring and Corrective Measures Reports" White Rose, February 2016, pg 20.

Moreover, despite all those lines of defense, ARB 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, ARB should not reduce the quantity of credits issued due to detection thresholds on the basis of conservatism</u>.

Apparent prohibition against fracturing the sequestration zone [Section C, §2.3(c)(3)(E)]

In the Geologic and Hydrologic Evaluation Requirement, the draft Protocol requires the project proponent to "estimate the injection volume and maximum allowable injection rate and pressure, such that neither the confining layer nor the sequestration zone hydraulically fracture during injection" [2.3(c)(3)(E)]. While the intent of this provision appears to be a prohibition on sustained injection of CO_2 above the fracture pressure of the storage complex, it could also potentially be read as a complete prohibition on fracture stimulation of the sequestration zone.

We believe that a constraint against fracturing the sequestration zone to be an unnecessary restriction so long as the confining layer is not fractured. Fracture stimulation of reservoirs is commonly applied in oil and gas production to initiate production in lower permeability reservoirs (or those that have formation damage from drilling and completion) or reverse a deterioration in injectivity from skin creation (e.g., via fines migration, scale development, etc.). In the CO_2 storage context, constrained fracturing may be necessary to achieve injection volumes and distribution and thus avoid pressure buildup that may itself compromise the integrity of the storage complex. Based on the in situ and laboratory geomechanical testing that will be conducted as part of the storage project characterization program and using the same sophisticated models developed for the unconventional production industry, the project developer will be able to determine how beneficial fracturing of the sequestration zone can be accomplished without risk to the confining layer or overburden system.

Injectivity tests and pump tests [Section C, §2.3(c)(4)]

The Geologic and Hydrologic Evaluation Requirement references "injectivity and pump tests of the sequestration zone" [2.3(c)(4)]. We recommend this requirement to be one or the other but not both. Some of the undersigned no longer recommend injectivity tests but prefer pump-off tests (the mathematical inverse). Injection tests with water can impair and fracture the storage zone and it is logistically challenging to conduct an injection test with CO_2. Given the Formation Testing and Well Logging Program section references doing either a pump test or injectivity tests [2.3.1(i)], our recommendation above may be consistent with ARB's original intention.

Requirement to conduct an injection test into each well's sequestration layer [Section C, §2.3.1(h)(1)]

ARB proposes requiring the operator to perform step rate tests for each CO_2 injection well that is part of the project and use the results of each test to determine the fracture pressure of the sequestration and confining layers [2.3.1(h)(1)]. We suggest ARB to require this test to be done for a representative well if it can be shown that storage reservoir/seal sequences are have generally similar characteristics as opposed to all injection wells. Injection tests using water, can damage the sequestration layer and conducting the tests with CO_2 can be logistically difficult. Further, we note that deliberately fracturing the rock at the casing shoe is self-damaging.

Laboratory analysis of caprock cores [Section C, §2.3.1(f)(1)]

We suggest that the requirement for coring [2.3.1(f)(1)] should be balanced against the damage that coring can do to the borehole (e.g. create washouts in susceptible formations). We recommend that additional core collection be required only if adequate data are not available. In current projects, operators sometimes develop a characterization well with extensive coring, and then drill injection wells with the best possible borehole conditions minimizing borehole damage. Coring the confining units carries especially high risk because mudstones typically are slow to core, and this long drilling time creates risk of oversize borehole and risk of poor centralization and flawed cement job. Core collection should be limited in injection wells because of this risk.

The timing of fluid sampling should not be over-specified. If fluid chemistry data are not urgent, then better quality fluid samples can be obtained at lower risk after casing and perforation. It should not be necessary to collect additional fluids once the performance objectives are met. Note that setting performance objectives to be accomplished by fluid sampling is important but retrieving fluids from depth is expensive and produces large volumes of purged waste water for disposal.

<u>The required analysis in the proposed Protocol should be changed to be site (and rock) specific, targeted to improve performance and reduce risk. Some performance-based objectives that could, if needed, be accomplished by collection of core and laboratory analysis of that core are:</u>

- <u>Provide conventional descriptions of the core collected to justify that laboratory analysis are representative of the flow units in the reservoir.</u>
- <u>Validate wireline-log porosity estimation for reservoir rocks</u>
- <u>If needed, provide fluid properties for wireline log and seismic analysis.</u>
- <u>Create and validate rock-specific porosity-permeability transforms to develop model inputs. Appropriate different techniques should be used for the injection and confining zones. Rock, fluid and log-specific optimization should be encouraged.</u>
- <u>Collect needed parameters to model multi-phase fluid flow, using special core analysis (relative permeability) relevant to CO_2 in the rock-fluid system. This is a time-consuming and expensive analysis and should be conducted once for the key rock type(s). Current best practices should be used</u>

- Provide any geomechanical parameters needed for seismic interpretation and modeling that can be obtained from core.
- Assess any opportunities to reduce risk using core analysis (for example via unexpected wettability or rock-fluid-CO_2 analysis), based on current best practices.

Simulation modeling requirements [Section C, §2.4.1]

Many commercially available tools are incapable of simulating physics that occur on an injection time-scale and physics that occur on a multi-thousand-year time scale as described in the Computational Modeling Requirement section [§2.4.1]. Hence, we caution ARB against being overly prescriptive with respect to modeling requirements. Requirements that are challenging to simulate may lead to simplifications that reduce accuracy. The signatories who are practitioners in actual geologic storage projects have concluded from experience that calibrating models to represent the relevant physics and to match historical trends is the best available approach to develop predictive capabilities. However, in complex systems with trend (e.g. expanding plume), limitations in the accuracy of the both the match and the prediction must be honored. Consequently, we recommend ARB to issue a functional requirement that the model effectively simulate the subsurface in a manner that is equivalent or better than the proposed requirements, and so as to give a good representation of the propagation of pressure and the migration of CO_2. Furthermore, such useful models should enable one to test whether the hypothesis of containment is confirmed by monitoring data. Finally, §2.4.1(a)(1)(B) references that models be designed to simulate heat flow. In operators' experience, simulation of heat flow is not normally important or done for CO_2 storage.

Corrective Action Plan [Section C, §2.4.3]

The requirement to determine the status of abandoned wells [§2.4.3(b)(3)] is potentially duplicative and/or contradictory of other requirements to identify wells that need corrective action. As ARB identifies in §2.4.3 (b)(4) and (c), wells that require corrective action include those that are improperly plugged or abandoned such that they may leak gas or fluid or those that are currently leaking gas or fluids, and/or wells that have been plugged and abandoned in a manner such that they could serve as a conduit for fluid movement into the subsurface that is likely to reach the atmosphere. §2.4.3(b)(3) however, appears to narrow the standard of proper plugging and abandonment to only require wells to have cement across all perforations and extending at least 100 feet above the highest of the top of a landed liner, the uppermost perforations, the casing cementing point, the water shutoff holes, the intended sequestration zone, or the oil and gas zone. We recognize that this language comes from DOGGR's proposed UIC regulations. However, this more limited and prescriptive standard falls short of the goals articulated in (b)(4) and (c) to broadly identify all wells that could allow CO_2 or other fluids to escape confinement, and should therefore be removed.

We support the recommended methods to identify existing wells that may need corrective action under §2.4.3(b), but are concerned that the flowchart in Figure 5 is inconsistent with those methods. The piece missing from the flowchart, but which is included in §2.4.3(b), is an assessment of whether existing records are adequate to determine the possible presence of wells and their plugging status. Oil fields in which CO_2 EOR is practiced typically have long production histories spanning decades. Some may have had multiple owners over this time. While some fields may have very complete well records, in others proprietary well files and well histories may be missing or incomplete, obscuring the location and plugging status of some wells within the field. State and federal records may also be incomplete, given that oil exploration and production in the United States predated the regulation of the practice by several decades in some cases. As such, the first step in identifying wells that need corrective action should be assessing whether existing records are adequate to identify all existing wells or whether more advanced methods may be necessary. ARB should amend the flowchart to add this step.

AOR reevaluation due to temperature and/or pressure changes three standard deviations from the average [Section C, §2.4.4.1(e)]

ARB is correct to require a re-evaluation of the AOR when changes in temperature and/or pressure readings are unexpected. However, the reference to three standard deviations from the average is misguided. Subsurface forecasting normally involves creating scenarios (e.g. low, mid/expectation and high). Only when actual data is significantly outside the low or high case is there cause for concern. Unless one does a full probabilistic workflow, there is no way to determine a "standard deviation from the average". Even if doing the full probabilistic workflow, one would generate a P10, P50 and P90 forecast – even a P1 and P99. Actual data can be compared to these to determine if conditions are outside of the P1 and P99, in which case actual results would be considered to have deviated from the forecast and a re-evaluation would be warranted. We recommend that ARB link reevaluations to performance results that are outside the low and high forecasting scenarios associated with the existing AOR or else triggered by performance data that is approaching a pre-defined limit deemed to be a threat to containment.

Well materials [Section C, §3.1]

Proper well design and construction are critical to achieving and maintaining mechanical integrity, which in turn is critical to ensuring storage integrity. We support the ARB's approach for the selection of well construction materials as specified in §3.1. Specifically, the requirement that casing, cement, and other materials used in the well be designed for the life of the well, compatible with fluids with which the materials may be expected to come into contact, and meet or exceed standards developed for such materials – as opposed to mandating the use of specific well construction materials – will provide operators with flexibility to help ensure that wells are designed and constructed to meet the specific needs of each individual site and project, and will achieve a higher degree of environmental protection by avoiding the blanket use of a particular material which may not be suited to a particular situation or location.

Cementing to surface [Section C, §3.1(b)(3)]

The requirement to cement from the bottom of the long string casing to the surface introduces different risks than a conventionally-completed well with cement lifted across the confining system. A number of casing and cementing options are currently available.[8] We recommend that ARB not specify the solution, but instead require that the best solution be assessed, justified and deployed, and that risk be

[8] See: http://petrowiki.org/Primary_cementing_placement_design

minimized. For example, current practices for cementing Class I wells to surface in Texas typically require adding cement diverters to the casing string. This results in introducing engineered holes in the steel casing, which could provide points of focused corrosion or geomechanical weakness during the long storage period. The currently proposed formulation may also exclude existing wells in oil fields from qualifying as injectors under the Protocol.

<u>We recommend that ARB modify this requirement to avoid unnecessary risk while assuring the required level of performance as follows</u>:

> "Injection wells must be engineered and installed to assure storage permanence for at least 100 years. The design should meet or exceed the performance created by the following practices:
>
> - Installing an effective casing string from the surface to the top of the sequestration zone; and
> - Assuring that a good quality cement-rock bond effectively seals the borehole-casing annulus from the top of the sequestration zone to the surface using a sufficient number of centralizers and circulating cement to the surface in one or more stages."

Temperature requirement for wellhead and valve design [Section C, §3.1(d)(2)]

We recommend ARB add a temperature related performance requirement for wellheads and valves [3.1(d)(2)]. Injection piping, valves and facilities should be rated to withstand temperatures from upset conditions, i.e. cooling from CO_2 expansion during an unplanned release.

Composition of CO_2 stream [Section C, §3.3]

A CO_2 stream is defined to mean:

> "CO_2 that has been captured from an emission source (e.g., a power plant), plus incidental associated substances derived from the source materials and the capture process, and any substances added to the stream to enable or improve the injection process",

while §3.3(c) states that:

> "[n]o injectate other than CO_2 must be injected except fluids used for well workovers and tests."

We support the CO_2 stream definition, which allows for incidental associated substances to be co-injected with CO_2. Alongside reducing CO_2 emissions, one of the benefits of CCS may be to also reduce emissions of other substances that affect air quality. <u>ARB should ensure that the definition of CO_2 stream is compatible with this notion.</u>

Furthermore, §3.3(c) appears to contradict the definition of "CO_2 stream" by requiring that no fluids other than (pure) CO_2 be injected. <u>ARB should revise this provision to state:</u>

"[n]o injectate other than <u>the</u> CO_2 <u>stream</u> must be injected except fluids used for well workovers and tests."

Tracking the extent of the *dissolved* CO_2 plume [Section C, §4.1]

The Injection Monitoring Requirements include a requirement to track the extent of the dissolved CO_2 plume [4.1(a)(9), pg. 73] yet the Plume Tracking requirement [4.3.2.1(a)] references only free-phase CO_2. Given the extreme difficulty in monitoring the extent of the dissolved plume – something that would require multiple observation wells and fluid sampling – and the fact that dissolved CO_2 is at far lower risk of leakage, we ask ARB to clarify whether the reference to monitoring dissolved CO_2 in §4.1 was intentional and, if so, to reconsider this provision.

Mechanical Integrity [Section C, §4.2]

Mechanical integrity and efficacy of wells is a high priority and thus it is critical these requirements reflect current best practices. Mechanical failure is a product of mechanical stress and strain. ARB's other proposed monitoring requirements advise these issues, such as seismic monitoring and pressure monitoring of the reservoir. While overall mechanical integrity of the reservoir is independent of well mechanical integrity, these monitoring methods provide a great deal of information about the likelihood of exceeding well mechanical parameters. As such, the information obtained from other monitoring requirements should help guide the rate and location of well mechanical integrity tests (MITs).

Additionally, ARB's proposed requirement [§4.1(a)(2)] for the use of continuous recording devices to monitor injection pressure, rate, and volume; pressure on the annulus between the tubing and the long string casing, and; the annulus fluid volume added is in fact a continuous test of internal mechanical integrity, thereby negating the need for separate, yearly internal MITs.

To gain crediting under the proposed protocol, the approaches proposed by ARB would need to be implemented everywhere, including outside the state. The risk of mechanical integrity failures varies geographically based on site-specific geomechanical factors, and therefore those should be taken into account when determining an appropriate MIT protocol. It is also important to consider the consequences of any potential integrity failure when designing the testing requirements. We recommend that ARB ensure flexibility in the MIT requirements based on site-specific conditions and analyses of risk, and to follow an "equivalent or better" approach like the one we suggest for cementing to surface.

Surface and near-surface monitoring [Section C, §4.3.2.2]

Surface and near surface monitoring can suffer from limitations at this complex interface. As proposed, the Protocol would have an operator set up a listed tool or tool combination and be in compliance without demonstration of a reasonable expectation that leakage detection would be effective. It is likely that at some sites, surface and near surface monitoring would be both more costly and much less effective than other monitoring approaches (such as geophysical- or pressure-based leakage detection, which can be conducted away from the complex and noisy surface interface). ARB should require deployment of the most effective technologies[9] and avoid over specifying the current limited portfolio

[9] An example of best practice is shown by Shell's Quest project: Shell Canada Limited, 2010, Quest Carbon Capture and Storage project, volume 1, project description, Appendix A, Measurement, monitoring, and Verification Plan.

of tools, so that the suite of monitoring strategies can adapt during rapid technology improvement. We recommend that ARB require the GCS Project Operator to conduct an analysis of the detection threshold of the proposed monitoring design and compare it against risk thresholds to optimize tool selection.

Many technologies have been proposed and evaluated,[10] however tool limitations are well known. High background CO_2 levels and high natural variability are serious barriers to detection of CO_2 leakage signal in near surface environments[11]. Turbulence of the boundary layer which dilutes signal is another major risk to detection. Boundary layer turbulence is increased by topography, vegetation, and land surface contrasts. These parameters are highly variable from site to site depending on biologic productivity, which in turn varies based ecosystem parameters. Site-specific parameters should be expected to potentially change over the project life because of climate change and changing surface conditions and usage. Even at the relatively simple land area selected for the Quest project (flat, treeless and agricultural, with remaining leakage risk focused at injection wells), significant barriers to deployment of many of the technologies are noted, and the current tools are considered experimental.[12]

Plume Stability [Section C, §5.2(b)(3)]

The concept of "plume stability" is used throughout this section, but is never defined – this is problematic.

The draft Protocol requires that once plume stability has been achieved, and at least 15 years after injection has stopped, the "monitoring wells must be plugged and abandoned" [5.2(b)(3)(G)]. This may be inconsistent with the schedule for bottom hole pressure tests and groundwater sampling [5.2(b)(3)(D)], which stipulates that groundwater monitoring frequency may be reduced once the plume has been stable for five consecutive years.

There is also an inconsistency in the timing of closure of all monitoring wells related to site closure. 5.2(d) requires that "*After* the Executive Officer has authorized site closure, the GCS Project Operator must plug all monitoring wells" (emphasis added). Pursuant to 5.2(b)(3)(G), all monitoring wells will have *already* been plugged at least 15 years after injection has stopped and plume stability has been achieved.

Several actions thus hinge on how and when "plume stability" is achieved post-injection. ARB must define the term. As with the term "pressure front", which could strictly be interpreted to include even infinitesimal increases in pressure, a strict interpretation of the term "plume stability" could be that of complete immobility of every injected CO_2 molecule. Not only is this not feasible in practice, but it also rules out situations where the plume may remain mobile for centuries while being asymptotically bound

At this site, risk assessment followed by monitoring design 1) identified potentially useful tools and technologies, and 2) down-selected based on expert opinion the tools must likely to reduce risk.

[10] See: IEA, Monitoring Selection Tool.

[11] Shell Canada Limited, 2010, section 6.5.5.

[12] Hirst et al., 2016.

within a given volume. For example, modeling of a "dip case"[13] indicates that plume stabilization can be established in a few years although plume migration continues but decreases with asymptotically.

Plume stability is best thought of as an established and unavoidable path towards plume containment within a volume with known and assessed leakage pathways. Establishing a trend towards plume stabilization in the post-injection site care context should entail integrating revised earth models and operational surveillance data to establish a reliable history match of observed actual and simulated CO_2 conformance (free CO_2 and pressure plumes) to date as a basis for systematically projecting such changes in the future. The CO_2 plume should be considered "stable" at that point in time when the pressure plume from injected fluids is returning towards original conditions, and risk assessment deems it very unlikely that the CO_2 plume itself will not encounter leakage pathways in the future by virtue of its current location and movement. On this basis, post-injection monitoring for establishing plume stability should be designed to address specific residual risk(s), and should be adjusted as additional monitoring information becomes available, rather than relying on pre-set time frames or methods (see further comments on the use of 3D seismic monitoring).

Furthermore, the potential variability in future storage project geologic settings and injection profiles render it unlikely that "plume stability" can be established at a predetermined time frame of 15 years. In some cases (such as complex, anisotropic geologic settings) a showing of plume stability may take longer, whereas in others (such as oil field anticlines with structural closure) it may be achievable during a shorter period.

<u>We therefore urge ARB to adopt performance-based criteria in accepting that plume stability has been demonstrated, and to not specify the required time frame</u>. This approach has been followed in the European Union CCS Directive (actual vs. modeled behavior of CO_2 conformance and evolution towards "long-term stability") and the US EPA UIC Class VI alternative time frame for post-injection monitoring (no longer poses an endangerment to USDWs).

Monitoring wells open for 15 years [Section C, §5.2(b)(3)(B)-(C)]

It is well documented that idle wells pose an increased risk to degradation and hence leakage.[14] Requiring that monitoring wells remain open for 15 years after injection has stopped introduces unnecessary risks, which are best avoided. Requiring the wells to be plugged and abandoned if leakage is detected is less risky. While keeping those wells open may be acceptable or advisable in some circumstances, requiring it in a blanket fashion is not. In a case where the plume is still moving distally, ARB's proposal to keep monitoring wells open (idle) for 15 years post-injection may only provide limited calibrating data – the value of this would need to be balanced against the increased well integrity risk associated with keeping those wells open.

[13] Doughty, 2011.

[14] See: RFF, 2016; Associated Press, 2015; CA AB2729, 2016; GWPC, 2011.

We recommend against mandating that monitoring wells remain open for 15 years in all circumstances, as this could introduce needless risks. The Executive Officer should retain the option to request such action under the Post-Injection Site Care and Closure Plan if this is necessary.

Mandatory 3D seismic surveys [Section C, §5.2(b)(3)(E)]

ARB has proposed repeat 3D seismic surveys to "map the position of the free-phase CO_2 plume and pressure front" [5.2(3)(E)], for a 15-year period following injection completion, during which period all wells associated with the project must be plugged and abandoned, except monitoring wells, which must remain open. We support the concept of an early, intensive monitoring period to demonstrate plume stability (also see comment on plume stability). Intensive monitoring right at the point when injection stops serves to inform the selection of the most appropriate techniques, and also to derive the appropriate time frame (longer or shorter) for further monitoring post-injection. However, we also see some problems with the proposed approach.

In California, potential storage venues and respective over- or under-burdens tend to be complex in terms of depth and structure/stratigraphy. The resolution of CO_2 plume detection may therefore range from adequate to poor. Whereas repeat 3D seismic can, under some circumstances, detect pressure (insofar as it is sufficient to affect acoustic properties), unraveling this signal from the free-phase CO_2 signal would be difficult.

We read ARB's intent to be that of establishing the extent and location of the CO_2 plume in the subsurface with a high degree of confidence as a surrogate for assessing the risk of leakage at the time when injection stops. We support this goal, but recommend that ARB state it explicitly and allow for the use of the most appropriate technique(s) in each case, provided it is approved by the Executive Officer, and if it provides equivalent or better information, rather than mandating the use of a technique (3D seismic) that may be of limited use, have unacceptable environmental consequences, and also happen to be unnecessarily costly. Accordingly, ARB should allow the use of proven alternatives to seismic (or inter-calibrations) with other technologies that may provide sufficient resolution to meet containment monitoring objectives.

ARB also references different methods for tracking the pressure front [4.3.2.1 (d)] indicating that the pressure front represents a source of concern at levels which would force fluids out of the storage formation. However, the pressure front may factually extend to a much wider area as it becomes vanishingly small. If repeat 3D seismic surveys are the appropriate method for establishing plume stability, we do not recommend extending seismic surveys to the limit of the pressure front but rather to the point at which the pressure no longer represents a risk to seal integrity and/or leakage.

Where the CO_2 plume is thin (<10m, or smaller than the seismic wavelength) it may not be possible to seismically image the free-phase CO_2. This would be an issue in thin, stacked beds or where the plume has "pancaked" at the top of a thicker reservoir, especially at distal extents of the plume. There are also potential complications with surface features interfering with wave source and reflection signals. Whereas seismic is often considered the ideal monitoring technique, it does not work well in every geologic setting and where it does, it is expensive and potentially disruptive to surface ecosystems and human populations. It is also not clear that the proposed timeline for surveys ("one year, three years, five years, and every subsequent five years after injection is complete, for a total of at least 15 years") would be ideal for imaging the position and movement of the plume. Rather, <u>if repeat 3D seismic surveys are the appropriate method for establishing plume stability, site-specific conditions, information from other monitoring techniques and history match simulations should be used to determine the appropriate survey frequency and coverage area.</u>

Post-injection monitoring after plume stability has been established [Section C, §5.2(b)(3)(G)-(H)]

ARB has also proposed soil gas and surface air monitoring at and near wellheads for a period of 100 years post injection [§5.2(3)(H)]. We see several problems with this approach.

Prescribed Soil Gas monitoring [§5.2(b)(3)(H)(1)]

Soil gas methods have been largely sidelined by researchers and practitioners as a useful means for detecting leakage from the storage compartment for the following reasons:

- Areal coverage by soil gas methods is limited. Examination of controlled release and natural analog sites shows that most leakage is focused in small areas a few meters across. These are likely to be missed even with a dense soil gas grid. Lateral migration of CO_2 within the soil because of soil structure is to be expected, measurements made near wells may not detect leakage.
- Noise is high. Large changes in CO_2 content in the soil are commonly observed, depending on complex biologic and soil physics interactions. This has been a recurrent problem from the first test studies conducted at Weyburn. California lacks a frozen ground season which is sometimes recommended to reduce biologic input and used to look for leakage. Separating leakage signal from background may be impossible using only concentrations; projects doing this type of monitoring must prepare to do an expensive attribution process on each anomalous measurement.[15]
- Trend in soil gas composition are likely to occur in response to changing climate. In addition, changes will occur in response to changes in land and water use. A baseline collected at project start is unlikely to be meaningful for leakage detection after decades of change, it could either cause abundant false positives or allow leakage to be undetected if soils grow more arid.
- Repeated soil gas monitoring at sufficient geographic and temporal spacing to serve as an active monitoring technology is currently quite expensive. Tools are not yet robust enough to be placed in the field unattended. If this technology is deployed, frequent repair and recalibration backed up by technician sampling should be budgeted.
- Note that many of the CO_2 soluble tracers available are strong greenhouse gases and ARB should weigh leakage risk against handling and manufacturing risk. Perfluorocarbon tracers sorb on

[15] Romanak et al., 2012, Dixon & Romanak, 2015, Anderson et. al, 2017

some substrates, therefore are not conservative.[16] In general, tracers have not been studied in controlled release contexts.

More information on these points can be found in the following:

Baubron, J-C. 2005. Soil gas velocity and flux modelling using long-term Rn monitoring: A new tool for deep CO_2 gas escape detection. In: Wilson, M., Morris, T., Gale, J. & Thambimuthu, K. (eds) Greenhouse Gas Control Technologies, Volume 2. Elsevier Science Limited., Oxford, 2115 – 2117.

Beaubien, S E, Jones, D G, Gal, F, Barkwith, A K A P, Braibant, G, Baubron, J C, Ciotoli, G, Graziani, S, Lister, T R, Lombardi, S, Michel, K, Quattrocchi, F and Strutt, M H. 2013. Monitoring of near-surface gas geochemistry at the Weyburn, Canada, CO_2-EOR site, 20012011. International Journal of Greenhouse Gas Control, Vol. 16, Supplement 1, S236-S262.

Bernardo, C., de Vries, D. 2011. Permanent shallow subsoil CO_2 flux chambers for monitoring of onshore CO_2 geological storage sites International Journal of Greenhouse Gas Control, 5, (2011)

Chiodini, G., Cioni, R., Guidi M., Raco, B., Marini, L. 1998. Soil CO_2 Flux measurements in volcanic and geothermal areas. Applied Geochemistry, Vol. 13, No. 5, pp. 543-552.

Elío J., Ortega, M.F., Chacón, E., Mazadiego, L., Grandia, F. 2012. Sampling strategies using the accumulation chamber' for monitoring geological storage of CO_2 International Journal of Greenhouse Gas Control 9 (2012) 303311.

Johnson, J.W. and Rostron, B.J. Chapter 4: Geochemical Monitoring In: Hitchon, B. (Ed). 2012. Best practices for validating CO_2 geological storage: Observations and guidance from the IEAGHG Weyburn-Midale CO_2 monitoring and Storage project. Geoscience publishing, Alberta, Canada. pp 353.

Jones, D G, Lister, T R, Smith, D J, West, J M, Coombs, P, Gadalia, A, Brach, M, Annunziatellis, A., Lombardi, S. 2011. In Salah Gas CO_2 Storage JIP: Surface gas and biological Monitoring. Energy Procedia 4 (2011) 3566ia JIP

Jones, D. G., Beaubien, S., Strutt, M. H., Baubron, J.-C., Cardellini, C., Quattrochi, F. Penner, L. A. 2003. Additional Soil Gas Monitoring at the Weyburn unit (2003). Task 2.8 Report for PTRC. British Geological Survey Commissioned Report CR/03/326.

Klusman, R.W., 2003. Rate measurements and detection of gas microseepage to the atmosphere from an enhanced oil recovery/sequestration project, Rangely, Colorado, USA. Applied Geochemistry, 18(12), 1825 – 1838.

[16] Gawey, M. R, 2013, Experimental analysis and modeling of perfluorocarbon transport in the vadose zone : implications for monitoring CO_2 leakage at CCS sites, University of Texas Masters Thesis.

Lafortune, S., Pokryszka, Z., Bentivegna, G., Chaduteau, C., Agrinier. P. 2011. First steps in coupling continuous carbon isotopic measurements with already proven subsurface gas monitoring methods above underground carbon dioxide storage sites. Energy Procedia 4

Risk, D., McArthur, G., Nickerson, N., Phillips, C., Hart, C., Egan, J., Lavoie, M. 2013. Bulk and isotopic characterization of biogenic CO_2 sources and variability in the Weyburn injection area. International Journal of Greenhouse Gas Control, 16S, (2013), S263-S275

Strutt, M. H., Beaubien, S. E., Baubron, J.-C., Brach, M., Cardellini, C., Granieri, R., Jones, D. G., Lombardi, S., Penner, L., Quattrocchi, F. & Voltatorni, N. 2003. Soil gas as a monitoring tool of deep geological sequestration of carbon dioxide: preliminary results from the EnCana EOR project in Weyburn, Saskatchewan (Canada). In: Gale, J. and Kaya, Y. (eds) Greenhouse Gas Control Technologies, Volume I. Elsevier Science Limited, Oxford, 391 – 396.

Welles, J.M., Demetriades-Shah, T.H., & McDermitt, D.K., 2001. Considerations for measuring ground CO_2 effluxes with chambers. Chemical Geology, 177(1-2), 3 – 13.

Prescribed Surface Air monitoring [§5.2(b)(3)(H)(1)]

Similarly to soil-gas monitoring, we have concerns that this required type of monitoring for detecting leakage at and near wells will be ineffective and not suited to the task. Please see comments above on §4.3.2.2.

Technological lock-in

The problems and limitations of these prescribed techniques are further amplified by the time frame over which they are required to be used. It will likely take several years to site and construct a new CCS project. This will then operate for a few decades. The proposed Protocol then prescribes the application of specific technologies over 100yrs. This amounts to a mandate to use these techniques for a period on the order of 150 years, during which period they will unquestionably be obsolete and replaced by far better alternatives. Even if the intent is to amend the Protocol in the future as technology evolves, we do not see the utility of this technological lock-in requirement at the present time.

Forestry vs. CCS from a technical standpoint

We understand ARB's primary basis for the 100-year post-injection monitoring provisions to be the precedent set in the agency's existing forestry offset protocol. While this may set a regulatory precedent to a limited extent, there are fundamental differences between forestry and CCS that need to be reflected in the requirements. We summarize those below.

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.[17]

[17] IPCC, Special Report on CCS.

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.
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 can 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,[18] and even smaller after wells have been plugged and abandoned.[19] The most severe events (surface blowouts still fail to produce significant leakage and are self-mitigating.[20]
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 that are 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. small in volume and correctable.[21,22,23,24]
Is leakage preventable?	Only to some degree. Even if the land is successfully set aside	Almost entirely. The entire premise of a CCS project is to

[18] 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.

[19] See Mordick, B., Peridas, G., 2017, Ch.7.

[20] 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 CO_2 well if the facility was used for CO_2 storage would be 0.37%. Due to the high density of CO_2, the well pressure at the rupture was less than half than for CO_2 compared to gas, which will make remediation easier." This represents an event that is very unlikely, and severe in its magnitude and duration.

[21] Celia et al., 2011.

[22] Kang et al., 2014.

[23] 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).

[24] Pawar et al., 2009.

	and guarded, natural causes may still cause leakage (loss of trees).	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.[25] 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.

Natural CO_2 releases are known to occur in nature. However, these are known to be slow, and to occur in geologic settings that would never be proposed or admitted as valid sequestration sites.[26] In geologic settings, CO_2 is placed ~1000m or more below the surface beneath layered rocks. If a leakage path should develop though the layers, migrating fluid would:

- Be slowed down by the layering;
- Be attenuated (smeared out as it seeps into pore space, dissolves in fluids, and reacts with rocks and organic materials); and
- Provide a detectable leakage signal such that loss could be limited or prevented.

Release of CO_2 from microscopic, partly water-filled spaces between rock grains (pores) is well known to be ineffective. The ineffectiveness of this system is demonstrated by the limits on producing oil and gas. No matter how hard the operator tries to produce hydrocarbon, a significant percentage, in the range of 20-80% of the hydrocarbon is left behind, trapped by capillary-dominated processes. CO_2 behaves the same way as oil and gas, it is driven by the same physics. In the case of an accidental release, since no engineered pumping or pressure replacement would be present, the percentage retained would be even higher. Technically, this is known as "non-wetting phase residual trapping", and is very reliably modeled as well as observed in the laboratory and in the field. A well that is opened in a CO_2-charged reservoir will not endlessly produce CO_2, but will "water out". In a study case, where CO_2 had been injected for about 6 years, this water-out took hours.[27] For the sites that would be allowed and certified under the

[25] Bachu & Watson, 2007 (presentation) and SPE paper.
[26] IEA GHG R&D Programme, "Natural Releases of CO_2".
[27] See Freifeld et al., 2016. However, the amount of retention by this process will be case-specific. Similar data on retention are available from the Frio test and West-Pearl Queen test.

proposed Protocol, leakage that amounts to a significant percentage of injected CO_2 is physically impossible.

Along these lines, and synthesizing the best available technical information, the IPCC concluded 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[28] 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."[29]

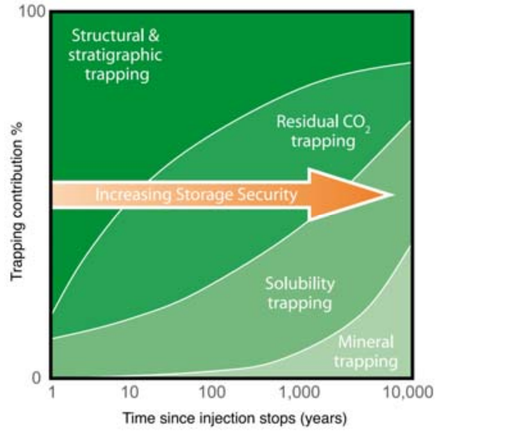
This points to expected levels of permanence that far exceed the 100-year standard that is embodied in the draft Protocol.

Summarizing in plain language:

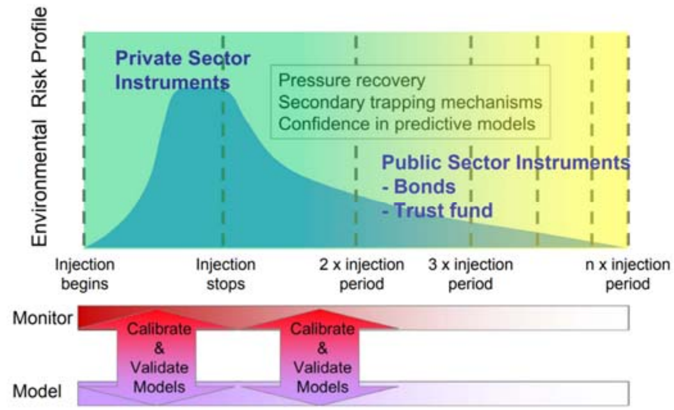
A CCS project under the proposed Protocol would be a highly engineered and managed affair that aims to minimize risks from the outset, increases confidence in performance and modeling significantly during operations over several decades, and establishes plume stability after injection stops. Wells are then plugged and abandoned, further reducing the risk of well leakage, while geologic trapping mechanisms reinforce and continuously reduce geologic leakage risk. Large losses, similar to those that are possible in forestry, under these strict circumstances are established to be impossible beyond doubt. We see no reasonable technical justification for requiring the same regulatory treatment as in the radically different situation of a forestry project in order to rule out any remaining suspicion of what can only be very small leakage from CCS projects. That is not to say that we consider this to be an invalid goal, especially for the purpose of public assurance, but we believe that the means prescribed are both incommensurate with the goal, and also incapable of achieving it.

[28] "Very likely" is a probability of 90 to 99%.

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



Storage Security as a Function of Time (Source: IPCC Special Report on CCS)



Environmental Risk Profile for CCS (Source: Benson, 2007)

Forestry vs. CCS from a legal standpoint[30]

We understand ARB's primary basis for the 100-year post-injection monitoring provisions to be a trial court's discussion of the agency's existing urban forest offset protocol. Statement of Decision, *Our Children's Earth Found. v. State Air Resources Bd*., Case No. CGC-12-519554 (Jan. 25, 2013); *see also Our Children's Earth Found. v. State Air Resources Bd.*, 234 Cal. App. 4[th] 870 (2015) (affirming the trial court decision without discussing the 100-year monitoring requirement). The trial court's limited discussion of this single offset protocol does not set a binding legal precedent that necessitates 100 years of monitoring under the CCS protocol. The trial court in that case did not conclude that 100 years of monitoring was necessary to establish the "permanence" of GHG reductions; the "permanence" of the offsets was not even at issue. Rather, the court's holding stands for the proposition that a 100-year compliance requirement was a reasonable basis for establishing the additionality of urban forest offset projects that might be occurring anyway, but where there is no obligation to carry the activities forward into the future. *Our Children's Earth Found.,* at 30. While this may set a regulatory precedent to a limited extent, it does not apply here. There are fundamental differences between forestry and CCS that need to be reflected in the requirements.

Relevant precedents

We present a list of precedents below that are not based on forestry, but are directly relevant to CCS.

- The operator of the Gorgon Carbon Dioxide Injection Project can apply for site closure at some point after injection operations have ceased. The time line 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 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.
- Quest 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.

[30] NRDC does not take a position on the legal opinions expressed in this comment.

- 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) 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 Occidental Petroleum 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.

Corporate responsibility

From the standpoint of industry, this requirement may have a chilling effect on investments in CCS. Very few companies have been in operation for 100-years and few are accustomed, willing, or able to underwrite commitments of this duration. If ARB decides that it is necessary to conduct monitoring over an extended period, there are ways this could be accomplished without holding the project operator responsible for this activity.

Stewardship issues

From an environmental perspective, placing a duty on a commercial entity to perform monitoring tasks for 100 years is likely to create a gap in duties. We can think of few, if any, corporations that have survived this long, and we are not confident that corporate successorship through takeovers, mergers or related developments will leave the duty to monitor intact.

Even though the draft Protocol's Financial Responsibility requirements include Post-Injection Site Care and Site Closure [§7(a)(2)(C)], ARB should not create a regulatory construct whereby the ability to monitor (or remediate) depends solely on corporations' prolonged existence or on financial responsibility instruments.

Such predicaments are best avoided by ensuring a shorter period of exposure to the risk of corporate discontinuity, and a clear and preemptive transfer of responsibilities to another entity with pre-defined duties and procedures using only a subset of the proposed financial responsibility instruments[31] or Buffer Account contributions.[32] Common law liability and statutory liability to deal with issues such as negligence, fraud, newly-emerged non-compliance and others would still apply to operators after injection stops regardless of whether an operator is required to monitor.

Recommendation

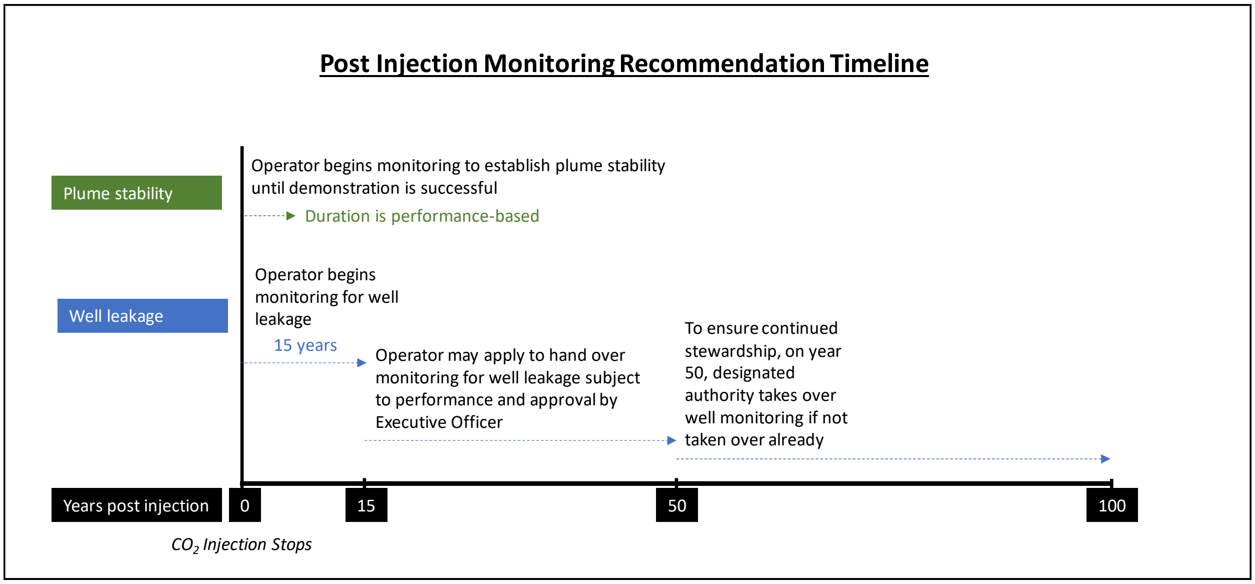
<u>We recommend that ARB modify its approach on these issues. The current approach, primarily based on regulatory precedent (forestry) and not science fundamentals, undermines the perception of ARB's faith in the effectiveness and reliability of many other requirements in the Protocol, fails to provide sufficient levels of environmental protection and assurance, and sets up a structure that is very likely to suffer from inherent implementation flaws. However, we believe that the elements that make up the current structure can be readily modified to achieve its objectives and accommodate the above concerns. Specifically, we recommend:</u>

- <u>In lieu of requiring post-injection soil gas and surface air monitoring in all cases, ARB should instead spell out clear objectives for post-injection monitoring for leakage from wells after plume stability[33] has been established, and allow for the use of a site-specific sensitivity analysis prior to deployment to determine the optimal tool type(s), location(s), sensitivity, and likelihood to detect leakage.</u>
- <u>Operator to be responsible for performing post-injection monitoring for leakage from wells for a minimum of 15 years, starting from the point when injection stops.</u>
- <u>EITHER: Ability for the Executive Officer to approve changes in the frequency of post-injection monitoring for leakage from wells, based on residual risk, project performance and operator performance.</u>
- <u>OR: Monitoring frequency to be every 5 years between years 1-20, and every 10 years thereafter.</u>
- <u>Ability for duty of post-injection monitoring for leakage from wells to be handed over to a designated entity if the operator can demonstrate all of the following to the satisfaction of the Executive Officer with a high degree of confidence:</u>
    - <u>Plume stability, as defined in the Protocol;</u>
    - <u>Well integrity and absence of leakage from all project wells at that time;</u>

[31] We have a higher degree of confidence in those instruments that can be readily liquidated, such as surety bonds and escrow accounts, compared to letters of credit or self insurance.
[32] See related comments under Buffer Account.
[33] The term "plume stability" should be defined – see relevant comment on this topic.

  - Proven ability to predict the behavior of the CO_2 plume over the operational and post-injection periods.
- If such a demonstration is made, and no later than 50 years after injection stops, post-injection monitoring for leakage from wells to be administered by a designated entity such as ARB, a designated trust specific to the project, or another suitable entity.
- Contributions to the Buffer Account during injection that are sufficient to cover post-injection monitoring for leakage from wells for up to 85 years (the permanence standard of 100 years minus the shortest term for which operators will be performing those duties).

Below is a schematic summarizing the proposed approach.



Deed notation [Section C, §5.2(f)]

We support the requirement to record a notation on the deed to the GCS project property or any other document that is normally examined during title search that will provide potential future owners of the property with information that it has served as sequestration site, along with other relevant information. This approach is preferable to the previously proposed ban on future activities at the project property.

Technology, market value changes, and/or additional usage opportunities associated with the storage complex may arise to justify or fail to prevent future activity. We believe there are other mechanisms that will preserve the option for such future activity without allowing the release of stored CO_2, and encourage ARB to consider alternatives.

We also urge ARB to take the following additional steps:

- For CCS operations in California that store qualified CO_2 through EOR or through saline storage, ARB should designate in-state storage complexes as covered entities (i.e. potential emission sources) under its climate programs such that any operator conducting activity within the storage complex or causing the potential release of CO_2 from the storage complex is responsible for ensuring such CO_2 is not emitted, is re-stored permanently, or accounted for as a new emission.

- For CCS operations outside of California that seek credits, ARB should require CO_2 storage operators to:
    - Provide assurance that transfer of liability for stored CO_2 is included in the terms of any purchase and sale agreement of the storage complex; or
    - Demonstrate the existence of storage permanence regulations that are functionally equivalent to California's; or
    - Demonstrate the existence of provisions for the transfer of storage liability to the other state post-closure, provided there is a bilateral agreement between that state and California that provides for permanent storage of that CO_2.[34]

Financial Responsibility [Section C, §7]

We generally support the Financial Responsibility requirements proposed under §7. However, pursuant to our recommendation for modified Post-Injection Site Care and Site Closure requirements (see relevant comment), we recommend that financial responsibility requirements for Post-Injection Site Care and Closure exclude what has already been contributed to the Buffer Account for the purposes of making funds available for a designated entity to perform monitoring and/or remediation after the duty of the CCS project operator has elapsed.

As noted in our comments on the Post-Injection Site Care and Site Closure requirements above, the environmental NGOs in our group are concerned that the use of some of the financial responsibility instruments listed under §7 would not be appropriate to deal with the proposed 100-year time frame and associated post-injection monitoring and/or remediation tasks.

Buffer account contributions [Draft LCFS Regulatory Text]

At its November 6, 2017 "Pre-Rulemaking Public Meeting to Discuss 2018 LFS Preliminary Draft Regulatory Text" workshop, ARB presented a range of possible contributions into the Buffer Account for CCS projects based on different analogues. We summarize our views on the relevance of these analogues below:

Analogue	***Contribution***	***Relevance***	***Reason***
ARB Forest Offset Protocol	10-21%	Very Low	See comments on Post-Injection Site Care. Entirely different nature of trapping and leakage mechanisms. CCS leakage far more predictable and preventable. Magnitude of possible

[34] Such agreements may not always be possible or desirable by other states, so ARB should examine these possibilities.

			leakage from CCS is far lower with a diminishing risk profile post-CCS injection.
Clean Development Mechanism	5%	Medium	Same technology, but CDM projects would take place under vastly different jurisdictions without the uniform applicability of standards such as those that the draft Protocol would impose.
American Carbon Registry	10%	Medium-High	Specifically written for CCS, but much narrower project envelope (monetary value of atmospheric leakage only), and option to use private insurance instead. ARB contemplates both financial responsibility requirements for a far broader suite of activities and eventualities [§7] and Buffer Account contributions.
Ontario Cap & Trade	3%	Low	This is a contribution by a basket of offset projects, some (or most) of which bear no resemblance to CCS in terms of the probability and magnitude of possible leakage.

Of these analogues, the closest is that of the American Carbon Registry (ACR) methodology. However, two key differences exist between the ACR methodology and ARB's proposal. First, ACR gives a blanket option to obtain private insurance in lieu of paying into a Reserve Account (as noted by ARB in its presentation) and only covers the monetary value of any potential atmospheric CO_2 emissions from leakage. Second, and even more importantly, ARB's proposed CCS Protocol contains an additional requirement to demonstrate and maintain financial responsibility sufficient to cover all of the following [§7(a)(2)(A)-(D) and §7(a)(3)]:

- Corrective action;
- Well plugging;
- Post-injection site care and site closure;
- Emergency and remedial response; and
- Potential endangerment of public health and the environment via atmospheric leakage.

ACR's methodology does not contain such provisions, but only references a simple requirement to "prove financial responsibility prior to gaining a permit to begin active injection operations".[35]

We therefore do not see the 10% in ACR's methodology as applicable in this case, due to the fundamentally different envelopes. In addition, an attempt to quantify the required magnitude of reversals for CCS projects paints a very different picture: Assume a risk of a CO_2 well blow-out on the order of $1x10^{-5}$ (one thousandth of a percent) in any given year[36,37] and using the very severe case of Aliso Canyon where it took ~112 days for control to be re-established. For an operation injecting 1 million tons CO_2 per year through a single well, 100 days of release would represent a loss of 307,000 tons of CO_2. With the risk of such an event being $1x10^{-5}$, the expected loss from a well blowout in any given year is about 3 tons or 0.0003% of the annual injection rate. For geological leakage, the risk of a loss of containment is an order of magnitude less than the risk of loss via a well.[38] But even if these risks were equivalent, a justifiable diversion of credits to a Buffer Account would be less than 0.01%.

We recommend that Buffer Account contributions by CCS projects be made up of two components:

- Making the system whole in case of a reversal (leakage) from a CCS project; and
- Making funds available for a designated entity to perform monitoring and/or remediation after the duty of the CCS project operator has elapsed (please refer to our Post-Injection Site Care and Site Closure comments above).

<u>For the former component, the worked example above suggests a contribution rate of less than 1% annually. For the latter component, we recommend that ARB and each project operator work through a site-specific calculation before injection begins in each case, revising this as the project operates and stops injecting as necessary, to estimate the needed size of the contribution, and amortizing that contribution over the projected injection period for the project.[39] A necessary accompanying</u>

[35] The American Carbon Registry, "Methodology for Greenhouse Gas Emission Reductions from Carbon Capture and Storage Projects" Version 1.0 April 2015, at §6.3.

[36] Failure Rates for Underground Gas Storage, UK Health and Safety Executive Research Report RR671, 2008.

[37] Evans D.J., West J.M., An Appraisal of Underground Gas Storage Technologies and Incidents for the Development of Risk Assessment Methodology, prepared by the British Geological Survey for HSE, 2008.

[38] As calculated for Shell's approved Peterhead storage project in the UK.

[39] The Alberta government levies C$0.23/$tCO_2$ injected to cover future liabilities, monitoring, and administration costs for CCS projects. Monitoring costs make up C$0.20. Risks make up C$0.02. The remainder is a levy for orphan wells.

modification would be to exclude this latter contribution from the financial assurance requirements of §7.

We further support the first two options of the proposed hierarchy of drawing on Buffer Account Contributions for CCS projects (retire CCS project contributions first; retire other CCS project contributions subsequently). At this point, we recommend against using CCS contributions for other project types and vice versa, given our expectation for a much lower risk of reversal from CCS. Instead, we recommend a delineation in the Buffer Account between project types, and a sufficient contribution from CCS projects for themselves in the first place.

New section to allow for the use of CCS [Draft LCFS Regulatory Text]

We are pleased to see the preparatory work to modify the LCFS regulation to allow for the use of CCS as a GHG mitigation option, and that the reference to a Board-approved quantification methodology has now been made specific in anticipation of this methodology being adopted next year.

We support the proposed eligibility for alternative fuel producers, refineries and oil and gas producers that capture CO_2 to receive credits [§95490(a)(1)(A)].

We also support proposed language that allows for captured CO_2 to be sequestered either on-site or off-site [§95490(a)(1)(A)]. This takes into account the important fact that the best geologic repository for CO_2 may not be located on-site.

Refinery investment credit [Draft LCFS Regulatory Text]

Carbon capture and sequestration involves a combination of technologies that benefit from economies of scale, and that are not worth pursuing de minimis. In additional to the substantial capital investment at the capture plant, a CO_2 pipeline must be permitted and constructed, a suitable geologic reservoir must be characterized authoritatively, and the right to inject acquired individually from all land owners whose property overlies the predicted extent of the CO_2 plume in the subsurface. Moreover, there are numerous sources of CO_2 at refineries. The best candidates for capture are the hydrogen production plant and the crackers. Combined, they typically amount to 20-25% of a refinery's total CO_2 emissions. It would not make economic sense to pursue all the necessary steps described above but not capture the bulk of CO_2 emissions from those sources. A smaller-scale project would be extremely unlikely to be implemented, with a possible exception being the testing of new technologies at smaller scales.

We support the inclusion of CO_2 capture at refineries, or at hydrogen production facilities that supply hydrogen to refineries, and subsequent geologic sequestration as an eligible project type under the Refinery Investment Credit Pilot Program [§95489(f)(1)(E)].

The current LCFS regulation text imposes two restrictions on credits from CCS installed at refineries. Stakeholders understand that these restrictions were originally placed to address (1) that the refinery investments were viewed as an alternative compliance mechanism to producing low-carbon alternative fuels and (2) the uncertainty on the credit market impact of some of the new technologies incorporated into the program.

§95485(d)(1) currently restricts the ability of a fuel reporting entity to using no more than 20 percent of credits generated through the Refinery Investment Credit to meet its annual compliance obligation. This would apply to CCS installed at a refinery as well. Concurrently, §95489(f)(1)(F) prevents the sale or transfer of these credits to any other party. Combined, those two provisions could mean that refinery CCS projects may need to be downsized significantly, potentially resulting in no major investments taking place using this technology.

<u>ARB should reexamine whether the applicability of the two constraints in the provisions mentioned above would preclude or unduly limit the use of this technology, which can result in significant emission reductions, and whether these restrictions are appropriate in this case. We support modification of §95485(d)(1) to potentially increase the 20 percent cap in order to avoid this, provided this does not compromise the main compliance mechanisms under the program and the smooth functioning of the credit market.</u>