MEMORANDUM

12/4/17

TO: **California Air Resources Board**

FROM: **Dr. Jens Birkholzer, Director Energy Geosciences Division, Berkeley Lab**

RE: **Comments on ARB's Draft Protocol for "Accounting and Permanence Protocol for Carbon Capture and Geologic Sequestration under Low Carbon Fuel Standard"**

The purpose of this memo is to discuss several issues of concern I have with ARB's DRAFT "Accounting and Permanence Protocol for Carbon Capture and Geologic Sequestration under Low Carbon Fuel Standard", in particular with regards to requirements for well monitoring as extracted below (highlights are my own):

(from pp. 91, and 95-96 of the protocol)

> 5.1. Well Plugging
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> (a) Well Plugging Plan: The GCS Project Operator must prepare, maintain, and comply with a plan to plug all injection, production, and monitoring wells associated with the GCS project that is acceptable to the Executive Officer.
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> 5.2 (b) (2) After injection is complete, the GCS Project Operator must continue to conduct monitoring as specified in this section and the Executive Officer approved Post-Injection Site Care and Site Closure Plan for a minimum of 100 years.
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> 5.2 (b) (3) (A) Within 24 months after injection is complete, all injection (and production, if applicable) wells associated with the GCS project must be plugged and abandoned pursuant to the Well Plugging Plan specified in subsection 5.1(d).
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> (D) The GCS Project Operator must conduct quarterly bottomhole pressure tests and groundwater sampling in the monitoring wells, in order to track the position of the free-phase CO_2 plume and pressure front. Once the CO_2 plume has remained stable for five consecutive years, well and groundwater monitoring may decrease to once per year, for a total of at

least 15 years after injection is complete.

(E) At one year, three years, five years, and every subsequent five years after injection is complete, for a total of at least 15 years, the GCS Project Operator must use three-dimensional surface seismic methods to map the position of the free-phase CO_2 plume and pressure front.

(F) The results from the direct and indirect monitoring methods described in subsections 5.2(b)(3)(D) and (E) must be used to update the AOR delineation pursuant to Section 2.4, determine if any corrective action is necessary, and to establish if the CO_2 plume has stabilized.

(G) After plume stability is established, and at least 15 years after injection is complete, the monitoring wells must be plugged and abandoned pursuant to the Well Plugging Plan in subsection 5.1(d).

(H) The GCS Project Operator is required to conduct leak detection checks at each well that is part of the GCS project, and in the near surface close to each well, annually for 100 years after injection is complete. Monitoring must include:

1. Soil-gas and surface-air monitoring at, and within 10 ft of, the wellhead; and

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

My most important comments are (1) that the 100-year duration of monitoring after injection is excessive and much longer than what should be required when monitoring for accounting and permanence, and (2) that it is not clear from the draft protocol what type of wells are meant where the protocol says “all injection (and production, if applicable) wells associated with the GCS project”. In addition, the memo points out that seismic monitoring methods are not suitable for mapping the pressure front. Here is some further detail on my reasoning.

1) My experience is that a 100-year time period for monitoring well leakage is overly conservative and not supported by the current scientific knowledge of GCS and its potential risks. The reasons for my assessment are as follows:

   a) Studies of core from CO_2-EOR wells have shown that portland cement retains its sealing capacity over decades of exposure to dissolved CO_2 in brine, and-induced geochemical alteration of well cements tends to reduce permeability and heal fractures in cement (Carey et al., 2007; Crow et al., 2010). Laboratory studies have confirmed that cement retains its sealing properties following exposure to CO_2-brine mixtures (e.g.; Kutchko et al., 2009). Therefore, the expectation is that well cement that is functioning properly to seal against leakage when subject to pressure gradients over the course of decades of CO_2 injection are not expected to degrade due to exposure to CO_2 over the decades of post-injection periods.

b) The specification of 100 years appears to be an arbitrary time period, not based on anything physical, chemical, or project-related. We are advocates of risk- and performance-based monitoring. Arbitrary time periods with no rationale undermine the technical credibility of regulations.

c) The US EPA Class VI regulations specify a 50-year time period for post-injection site care (PISC), but allow a shorter period at the discretion of the EPA Administrator. We recommend the ARB adopt the 15-year period following plume stability as the specified time for PISC and also insert the possibility of a shorter period at the ARB's discretion.

d) Following cessation of injection, free-phase CO_2 plumes will tend to stabilize, i.e., stop growing and stop migrating. Upon confirmation of plume stability, the wells that are intersected by the free-phase CO_2 plume will be known. Lingering injection over-pressure and CO_2 buoyancy create a driving force for leakage in wells intersecting the free-phase plume. In contrast, wells intersected by the dissolved-CO_2 plume are not under as large a threat of leakage because there is no buoyant component to the upward driving force in wells perforated in brine with dissolved CO_2. The protocol does not state which wells are subject to monitoring for 100 years. We believe that only the fraction of wells intersecting the free-phase plume would be vulnerable to elevated leakage likelihood, and as pointed out above, there is no reason to expect degradation of cement due to reactions with CO_2.

e) Finally, the ARB protocol allows for revocation of the permanence certification (8(a) (p. 107) provision for revocation and/or re-issuance of permanence certification), so that if surface or subsurface leakage is suspected or detected, new monitoring efforts could be established following the end of PISC.

2) Given that all injection and production wells are required to be plugged after 24 months, and that monitoring wells are required to be plugged after plume stability is established, and at least 15 years after injection is complete, what are the wells that are "part of the project" and that need to be monitored for 100 years? Are *all wells* in the AOR "part of the project," or are project wells only the injection, production, and monitoring and possibly characterization wells that were *installed* as part of the project? Furthermore, is definition of AOR based on extending to the limit of dissolved CO_2, or the extent of the pressure front which is often larger than the former (Birkholzer et al., 2015)? I recommend using the area which extends to the limit of dissolved CO2, since that is the area where leakage of CO2 could occur and potentially lead to GHG emissions back to the atmosphere.

3) In (E) above, the rules state, "Operator must use three-dimensional surface seismic methods to map the position of the free-phase CO_2 plume and pressure front." Seismic methods are capable of mapping the free-phase CO_2 plume, but to my knowledge are not useful for mapping the pressure front. The proposed requirement to use it for this purpose should not be included in the final accounting and permanence protocol without further explanation.

In summary, for the reasons given above, I strongly suggest reconsidering the requirement for a 100-year duration of monitoring "project wells" after injection. My recommendation is that ARB adopt the 15-year period following plume stability as the specified time for PISC and also insert the possibility of a shorter period at the ARB's discretion. GCS researchers have learned in a large number of applied research projects—comprising simulation, risk assessment, laboratory and field studies, that the risk of CO2 leakage decreases after injection (as a result of plume stabilization and pressure reduction) and that a 100-year monitoring period is excessively long.

I strongly believe that carbon capture and geologic carbon sequestration is an important climate mitigation method that is ready for large-scale deployment today. And I believe it is important to fully support the potential role that GCS can play in reducing California's carbon dioxide (CO_2) emissions and to not place unnecessary regulatory burden on its implementation under LCFS. Most studies of California's potential climate mitigation strategies conclude GCS is needed to meet the state's greenhouse gas reduction goals (Greenblatt and Long, 2012).

References

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