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Manager Emerging Technology Section
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P.O. Box 2815
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Subject: Comments to the California Air Resources Board, Carbon Capture and Sequestration Protocol under the Low Carbon Fuel Standard

Dear Mr. Mitchell:

Occidental Petroleum Corporation ("Occidental") appreciates this opportunity to provide comments on the California Air Resources Board's Carbon Capture and Sequestration Protocol under the Low Carbon Fuel Standard ("Protocol").

Occidental is the largest injector of carbon dioxide ("CO_2") for enhanced oil recovery, or EOR, in the Permian Basin of West Texas and southeast New Mexico and an industry leader globally in this technology. Occidental operates 34 CO_2 floods, over 2,500 miles of CO_2 pipeline and 14 CO_2 separation and recycling facilities. In 2017, we injected more than half-a-trillion cubic feet of CO_2, or over 27 million metric tons. From this CO_2, about 40 to 50 percent is newly sourced from Occidental and other commercial suppliers, and the remainder is recycled from existing producing wells. Over time, virtually all injected CO_2 becomes sequestered in the oil and gas reservoir.

In 2015, the U.S. Environmental Protection Agency ("EPA") approved a Monitoring, Reporting and Verification ("MRV") plan for simultaneous CO_2 injection and sequestration for Occidental's Denver unit operations in Texas. This was the first-of-its-kind MRV Plan approved by the EPA and represents an important milestone in the development and commercialization of carbon capture, utilization and storage technology as an approach for long-term management of greenhouse gas emissions. In 2017, Occidental received approval for a second MRV plan for its Hobbs unit operations in New Mexico. These remain the only two approved MRV plans for CO_2-EOR that the EPA has approved for sequestration incidental to EOR. A third MRV plan submitted by a different company has been approved for deep saline sequestration. The continuing use of natural sources of CO_2 in EOR is essential to support investment in and expansion of infrastructure that can be used in the future to transport and inject CO_2 from man-made sources.

For Occidental, CO_2 is a commodity that has significant value. Occidental carefully manages its CO_2 in a manner that reflects its significant value to our enhanced oil recovery operations. We strive to avoid any preventable losses of the commodity because CO_2 represents a significant operating expense; the loss of a CO_2 molecule represents a corresponding increase to Occidental's operating expenses. Occidental's attached comments reflect its perspective that CO_2 is a valuable commodity that must be managed to minimize loss, whether in the form of fugitive emission from pipelines, valves and compressors or from a penetration into a reservoir.

We welcome the opportunity to discuss our comments either in person or via a conference call. I may be reached at (202) 857-3000.

Best regards,

Al Collins mpc

Al Collins
Sr. Director – Regulatory Affairs

Encl.: Attachment A

Attachment A

Comments to the Carbon Capture and Sequestration Protocol under the Low Carbon Fuel Standard

March 6, 2018

Our comments are organized with the current proposed Protocol provision, or excerpt, that we are commenting on repeated first. We then provide an explanation of how we understand the proposed Protocol provision and challenges we see in implementation. We close the comments with suggested revisions to the current proposed Protocol that we believe ensures that the Protocol will achieve CARB's goals and ensure permanent sequestration of CO_2 while increasing the likelihood that a CCS Project will be able to meet the Protocol's exacting standard.

1. C.2.3(c)(6). A CCS Project Operator must submit (along with other information) "a full description of all geologic structure, including faults and fractures, which intersect the storage complex and all data relevant to the transmissivity of these features…including (A) the location, depth, displacement, and geometry of the fault or fracture...(C)...a full geometric description in support of...."

   A description of the geologic structure is essential to assessing the risk of a storage complex. We understand the intent of this provision is to capture structures, including faults and fractures, that might provide leakage pathways. However, a <u>full</u> description of <u>all</u> structures may not be possible because not all subsurface structures are known or measureable. The majority are fine hairline cracks of limited length that do not pose a risk of leakage. To recognize that all faults and fractures are not identifiable or a risk, we suggest this alternate language:

   C.2.3(c)(6). A description of known geologic structures, including all significant faults and fractures, which intersect the storage complex and all available data relevant to assessing the transmissivity of these features…including (A) the location, depth, displacement, and geometry of the faults or fractures that can be mapped...(C) a sufficient description in support of...."

2. C.2.3.1(a). A CCS Project Operator must submit a Formation Testing and Well Logging Plan with the Sequestration Site Certification. The plan must demonstrate to the Executive Officer how the CCS Project Operator will collect geologic and hydrogeologic data required to show the selected storage complex is suitable for receiving and containing CO_2.

   This and other requirements in this section appear to apply to new projects. Occidental will be submitting a Sequestration Site Certification for one or more of its existing CO_2-EOR projects. In lieu of a formation testing and well logging plan that meets each of the specific provisions in the Protocol, Occidental can provide decades of data describing the sequestration zone and storage complex in detail. We read the language in this section and others as providing guidance, e.g., C.2.3.1(b) states that "[t]his section provides guidance on the formation testing and well logging activities that a CCS Project Operator must conduct...." This suggests that there should be flexibility in the information that a project applicant is required to submit for a particular CCS Project. E.g., in a CO_2-EOR field, continuous monitoring data can demonstrate with greater certainty that a storage complex is suitable for receiving and containing CO_2 and a plan to collect geologic and hydrogeologic data may not be needed.

We suggest this alternate language that recognizes that the Executive Officer should have and exercise an appropriate level of discretion for existing projects:

C.2.3.1(b). This section provides guidance on the formation testing and well logging activities that the CCS Project Operator must conduct to generate the information and data required to confirm that the storage complex is able to meet the permanence requirements for carbon sequestration, as required in subsection C.1.1.2. For CO_2-EOR the information required may vary where the Executive Officer determines that historical data provides an equivalent demonstration that the selected storage complex is suitable for receiving and containing CO_2.

3. C.2.4.1(a)(1)(A). The CCS Project Operator must delineate the AOR using a computational model that, among other things, predicts the lateral and vertical migration of the free-phase CO_2 plume and pressure front, as well as the dissolved CO_2 plume and formation fluids in the subsurface....

   A CO_2-EOR project simply does not feature a pressure front. Rather the field pressure is stabilized. This is a critical difference between an existing CO_2-EOR project that stabilizes pressure in the zone to maximize enhanced oil recovery, and a sequestration project that pressurizes a reservoir through continuous injection. Consequently, predictions of the CO_2 pressure front should not be required.

   We suggest the following additional language be inserted that recognizes this difference:

   C.2.4.1.(a)(1)(A). For CO_2-EOR projects, the computational model must predict the movement of CO_2 in the subsurface….

4. C.2.4.1(a)(2). The computer code utilized in the AOR delineation model must be open source and publically available to CARB and CCS Project Operators….

   CO_2-EOR operators such as Occidental do not use open source computer models. Occidental purchases licenses to use proprietary commercially available models. While it is possible that an open source code may work for sequestration projects with a small number of injectors, for CO_2-EOR projects with hundreds of injectors and thousands of producers, open source codes are simply not able to process all the available data and provide meaningful results. In Occidental's case, we purchase three licenses for software models. These models are more robust, accurate and provide results superior to those publically available models.

Occidental has explored using a subset of our data in a publically available open source code for purposes of complying with the protocol. However, we have learned that it is not feasible to take the enormous amount of data that we have collected on our operations and covert it for use in an open source code and any results we may obtain would be inferior to those from the proprietary commercially available model we are using.

We suggest that this language be revised to permit the use of a proprietary commercially available model as follows:

C.2.4.1(a)(2). The computer code utilized to model the AOR may be open source and publically available to CARB and CCS Project Operators or a validated proprietary commercially available software….

In the alternative, our CO_2-EOR modelers suggest several other solutions to ensure that CARB is comfortable with the modeling data Occidental uses, including (A) inviting CARB personnel to observe the modeling exercise, (B) having an independent third party certify the modeling results; or (C) performing and reporting on an audit of the models.

5. C.2.4.4(c)(1). CCS Project Operators must update and verify the site model and re-evaluate the size and shape of the AOR when…material changes have occurred such that the actual CO_2 free-phase plume or pressure front extend beyond the area originally modeled….

   As described above, a CO_2-EOR project simply does not feature a pressure front. Rather the field pressure is stabilized. This is a critical difference between an existing CO_2-EOR project that stabilizes pressure in the zone to maximize enhanced oil recovery and a sequestration project that pressurizes a reservoir through continuous injection.

   We suggest the following additional language be inserted that recognizes this difference:

   C.2.4.4(c)(1). CCS Project Operators must update and verify the site model and re-evaluate the size and shape of the AOR when…material changes have occurred that significantly alter the predicted or measured subsurface movement of CO_2 within the sequestration zone.

6. C.2.4.4.1(c)(1). Triggers for an unscheduled AOR reevaluation include observed migration of the plume in any direction that is faster than predicted by the model…..

   Occidental recognizes that an AOR reevaluation may be appropriate in certain circumstances. However, the use of the phrase "faster than predicted" is imprecise. CO_2

in a CO_2-EOR project may move at varying velocities based on operating conditions that may change. We suggest the following revision:

C.2.4.4.1(c)(1). Triggers for an unscheduled AOR reevaluation include indications that the subsurface CO_2 movement, observed from injection and, in the case of CO_2-EOR, production behavior, is migrating beyond the acceptable range predicted by the model.

Similarly, C.2.4.4.1(c)(2) states, triggers for an unscheduled AOR reevaluation include observed thickness of the CO_2 plume that is much thinner than that predicted by the model. For CO_2-EOR CO_2 plume thickness is not a meaningful measure because oil and CO_2 have the same resistivity index and the low permeability of the formation renders seismic data of limited utility. We can and do make adjustments to ensure CO_2 is being injected and maintained in the targeted reservoir as predicted by simulation models. We understand CARB's intent as requiring a revaluation when there is some indication that subsurface conditions are not as expected or predicted. We suggest the following wording to account for variations between different formations that might be used for CO_2 sequestration:

C.2.4.4.1(c)(2). Triggers for an unscheduled AOR reevaluation include indications that the subsurface CO_2 movement, observed from injection and, in the case of CO_2-EOR, production behavior, is not consistent with model predictions and suggests movement of CO_2 outside of the intended formation.

7. C.3.1(c)(1). All well materials must be compatible with the fluids with which the materials may be expected to come into contact with and must meet or exceed standards developed for such materials by API, ASTM or comparable standards acceptable to the Executive Officer.

   All well materials must be selected and formulated to minimize corrosion caused by fluids that the materials may be expected to contact. Tubular well components must meet or exceed standards developed for such materials by API, ASTM or comparable standards acceptable to the Executive Officer – e.g. corrosion inhibitors may be added to wells in a CO_2-EOR project to retard corrosion as well as using CO_2 resistant coatings on injection well tubulars. Annular sealant materials between wellbore and tubular components must be corrosion resistant to CO_2 and formation fluids within the sequestration zone. We believe the aforementioned measures satisfy the intent of this provision but suggest the following revision to the language for clarification:

   C.3.1(c)(1). All well materials must be constructed to minimize corrosion caused by the fluids with which the materials may be expected to come into contact with and must meet or exceed standards developed for such materials by API, ASTM or comparable standards acceptable to the EO. E.g., corrosion inhibitors may be added to wells in a CO_2-EOR project to retard corrosion.

Similarly, C.3.1(c)(5) states that cement and cement additives must be compatible with the CO_2 stream and formation fluids within the sequestration zone. We suggest the following revision:

C.3.1(c)(5). Cement and cement additives must be corrosion resistant to the CO_2 stream and formation fluids within the sequestration zone.

8. C.3.2(a)(1). During drilling and construction of wells, the CCS Project Operator must…determine or verify permeability and porosity….

   In CO_2-EOR we do not test during drilling because of the presence of drilling fluids in the well. We wait until the well has stabilized after drilling. Otherwise, drilling mud and other residues would compromise the results. We suggest revising the language as follows to clarify that in CO_2-EOR projects, testing occurs after drilling and is part of the construction of a well:

   C.3.2(a)(1). When drilling and constructing wells, the CCS Project Operator must…determine or verify permeability and porosity….

9. C.3.2(c)(1). The CCS Project Operator must submit…a descriptive report that includes interpretation of the results of…(1) Deviation checks during drilling on all holes constructed by drilling a pilot hole that is enlarged by reaming or other method.

   We have had Occidental's drilling and completion specialists examine this provision and it is not clear what is required or what CARB intends. Occidental personnel advise that at no point would we drill a pilot hole that is enlarged by reaming or other method. We request that CARB review this provision and provide clarification as to its intent and application.

10. C.3.3(b). The CCS Project Operator must ensure that injection pressure does not exceed 80 percent of the fracture/parting pressure of the sequestration zone so as to ensure that injection does not initiate or propagate existing fractures….

    Occidental recognizes the need to prevent injection pressures from exceeding the fracture/parting pressure. An understanding of the fracture/parting pressure is critical to Occidental's business, maximizing oil recovery, avoiding the propagation or initiation of any existing fractures, and safeguarding against the loss of CO_2. In Occidental's case, we use a SCADA control system architecture to continuously monitor subsurface conditions to ensure, among other things, that fracturing/parting pressures are not exceeded. Occidental CO_2-EOR projects inject at pressures 50 psi below fracture/parting pressure. Depending on the reservoir, this may be greater than 80% of the fracture/parting pressure. We suggest the following revised language to recognize CO_2-EOR operating conditions:

C.3.3(b). The CCS Project Operator must ensure that injection pressure is continuously monitored and for CO_2-EOR Project Operators is at least 50 psi below fracture/parting pressure.

Similarly, C.4.3.1.3(c) states that the CCS Project Operator must ensure that the injection pressure remains at or below 80 percent of the fracture pressure of the sequestration zone. We suggest the following revised language:

C.4.3.1.3(c). The CCS Project Operator must ensure that injection pressure is continuously monitored and for CO_2-EOR Project Operators is at least 50 psi below fracture/parting pressure.

11. C.3.3(f)(1). If a shutdown is triggered or a loss of mechanical integrity is discovered, the CCS Project Operator must (1) immediately cease injection, otherwise all credits generated are subject to invalidation; …(3) notify the Executive Officer in writing within 24 hours….

    CO_2-EOR projects have much in common with other industrial processes. Like industrial processes, computer control systems may alarm from time to time for minor issues and operator intervention is required to check and reset the system. Occidental utilizes a SCADA control system to monitor its CO_2-EOR operations. The system is designed to continuously monitor conditions within the EOR operation. Events beyond Occidental's control and that do not reflect a downhole upset condition may occur that could trigger a shutdown. E.g., inclement weather that may cause a temporary interruption of power, voltage spikes, an unexpected failure of a monitoring probe or wiring despite proper and timely checks and maintenance. In many of these cases, the SCADA will trigger an alarm and may shutdown injection until the situation can be checked and repairs, if needed, initiated. None of these events risk a loss of CO_2 from the reservoir and we don't believe that it is CARB's intent to have the protocol require 24-hour written notice for all events. Rather, we understand that CARB seeks to have notice of significant events. We suggest that minor events of the nature describe above should be reported quarterly or annually. Accordingly, Occidental agrees that major event, e.g., a system failure accompanied by a loss of sequestered CO_2 from the reservoir should trigger notice to the Executive Officer. To recognize these scenarios, we suggest the following revisions:

    C.3.3(f)(1). If an un-remedied shutdown is triggered or a loss of mechanical integrity is discovered with an accompanying loss of CO_2 from the sequestration zone that results in an invalidation of LCFS credits, the CCS Project Operator must (1) immediately cease injection, otherwise all credits generated are subject to invalidation[1]; …(3) notify the Executive Officer in writing within 24 hours….

Similarly, C.3.4(a) states that the CCS Project Operator must cease injection into the affected injection well and must not resume injection…without Executive Officer subsequent approval if (1) MI testing has not been performed as required; (2) the well fails MI; (3) an automatic alarm is triggered….

Again, an automatic alarm could be triggered by a relatively benign process condition or other conditions like inclement weather. We do not understand CARB's intent as requiring Executive Officer approval to restart injection after a CO_2-EOR operator responds to and corrects a false alarm or other relatively benign and corrected operating condition. We suggest the following revisions:

C.3.4(a). The CCS Project Operator must cease injection into the affected injection well and must not resume injection…without EO subsequent approval if (1) MI testing has not been performed as required; (2) an un-remedied automatic alarm is triggered with an accompanying loss of sequestered CO_2 that results in an invalidation of LCFS credits, ….

12. C.4.1(a)(2). Testing and monitoring associated with CCS projects must include…(2) installation and use…of continuous recording devices to monitor…(3) the annulus fluid volume added….

    In CO_2-EOR operations, we monitor the annulus pressure rather than the annulus fluid level. We suggest the following revision to recognize this well requirement:

    C.4.1(a)(2). Testing and monitoring associated with CCS projects must include…(2) installation and use…of continuous recording devices to monitor…(3) annulus fluid volume, if present….

13. C.4.3.2.1. CCS Project Operators are required to track the extent of the free-phase CO_2 plume, and the pressure development (e.g., the pressure front) by using: (1) Direct methods in the sequestration zone, and (2) Indirect methods such as seismic, electrical…downhole CO_2 detection tools….

    As described above, a CO_2-EOR project simply does not feature a pressure front. Rather the field pressure is stabilized. This is a critical difference between an existing CO_2-EOR project that stabilizes pressure in the zone to maximize enhanced oil recovery and a

[1] Although the suggested revision retains the term "invalidation", Occidental submitted comments related to this on April 23, 2018. The comments on page 15 of the attached link should be considered simultaneously with the suggested revisions. https://www.arb.ca.gov/lists/com-attach/123-lcfs18-BmpWMwZhU3NVDFc0.pdf

sequestration project that pressurizes a reservoir through continuous injection. We suggest the following revisions:

C.4.3.2.1. CCS Project Operators are required to track the extent of the free-phase CO_2 plume, and the pressure development (e.g., the pressure front) by using: (1) Direct methods in the sequestration zone, and (2) Indirect methods such as seismic, electrical…downhole CO_2 detection tools… CO_2-EOR Project Operators are required to continuously monitor the subsurface movement of CO_2 by using: (1) Direct methods in the sequestration zone, and (2) Indirect methods such as seismic, electrical…downhole CO_2 detection tools….

14. C.4.3.2.3 (a). The CCS Project Operator must deploy and maintain a permanent, downhole seismic monitoring system….

    Because CO_2-EOR projects stabilize the reservoir field pressure to enhance oil recovery, there is no risk of over-pressurization and no risk of seismic activity associated with CO_2-EOR. As a result, Occidental does not deploy a seismic array consisting of a permanent, downhole seismic monitoring system. Occidental does monitor TexNet, a system installed by the University of Texas at Austin's Bureau of Economic Geology. We suggest the following revision:

    C.4.3.2.3. The CCS Project Operator must deploy and maintain a permanent, downhole seismic monitoring system….A CO_2-EOR Project Operator may choose to monitor seismic activity consistent with C.4.3.2.3(b).

15. C.5.2(b)(3)(A). Within 24 months after site injection is complete, all injection (and production, if applicable) wells associated with the CCS project must be plugged and abandoned pursuant [sic] subsection C.5(d), with the exception of any wells that the CCS Project Operator plans to transition into observation or monitoring wells.

    In the course of operation, CO_2-EOR projects may repeatedly convert CO_2 injection wells to water injection wells and then return the wells to CO_2 injection. Requiring plugging and abandoning of such wells is not necessary and does not reflect the nature of CO_2-EOR operations. In addition, we read this requirement as not being triggered until the entire site enters into the Post-Injection Site Care period. To provide clarity, we suggest the following revision:

    C.5.2(b)(3)(A). Within 24 months after the CCS Project enters into the Post-Injection Site Care period, all injection (and production, if applicable) wells associated with the CCS project must be plugged and abandoned pursuant to subsection C.5(d), with the exception of any wells that the CCS Project Operator plans to transition into observation or monitoring wells.

16. C.5.2(f). Within 30 days each CCS Project Operator must record a notation on the deed of the CCS project property…that will in perpetuity provide any potential purchaser of the property the following….(1) the fact that the land has been used to sequester CO_2….

    This provision is similar to C.9(b), which requires that full disclosure must be made to inform future land management or development within the AOR. For example, the restrictions and disclosure must be recorded on the deeds of the land when no regulations are in place to address this issue.

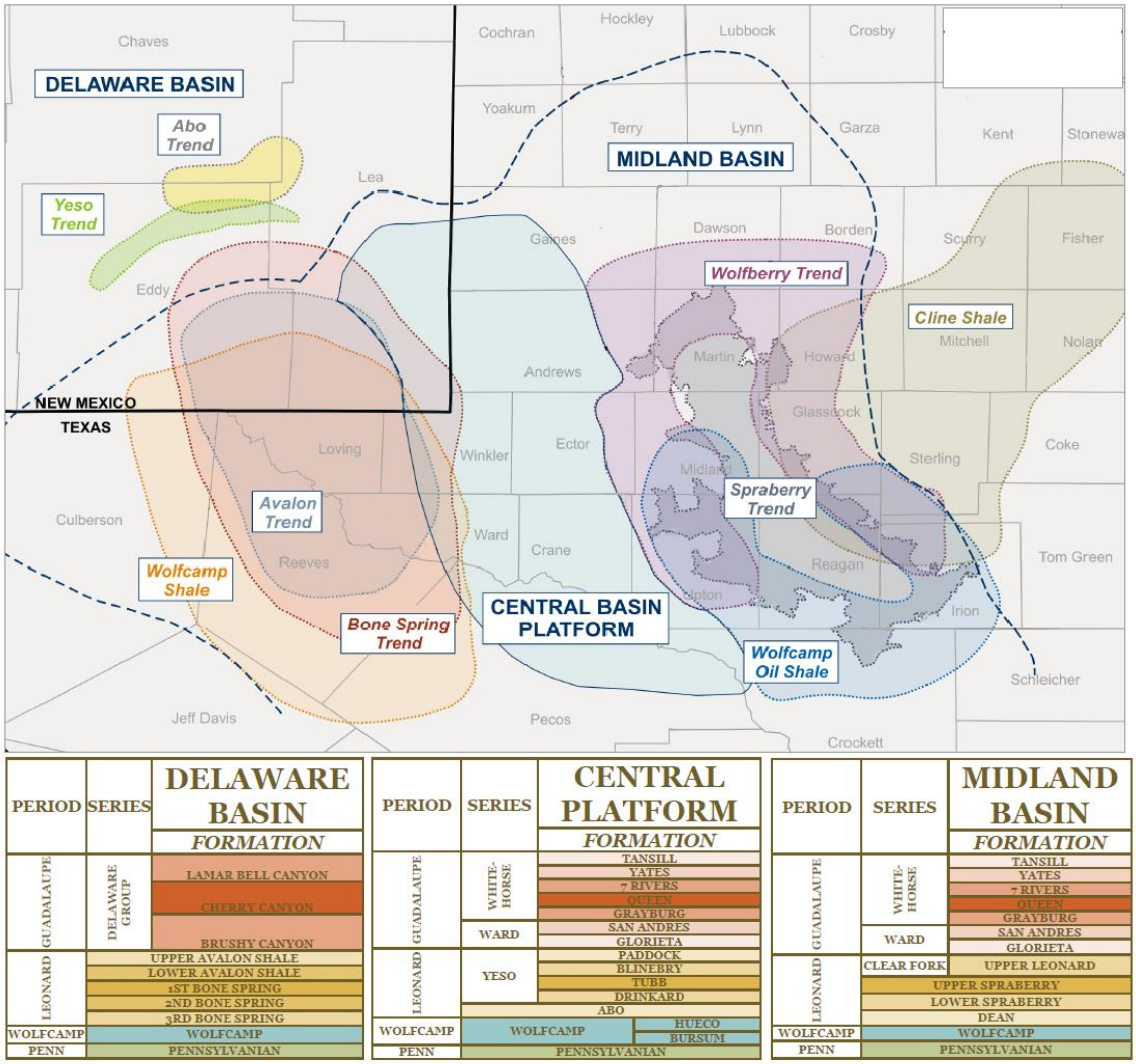
    Occidental suggests that compliance with either provision should satisfy the notice requirement CARB seeks. Further, a demonstration of compliance with either provision should not be required until the project enters the Post-Injection Site Care period. Finally, Occidental suggests that a 30-day period is too brief to permit a project operator to complete deed recordation for a CO_2-EOR project that may underlie properties owned by multiple unrelated parties.

    We suggest the following revision:

    C.5.2(f). Within three years after the project enters the Post-Injection Site Care period, each CCS Project Operator must disclose…to any potential purchaser of the property the following….(1) the fact that the land has been used to sequester CO_2…or demonstrate that existing regulations are in place to provide notice to potential purchasers.

17. C.9(c). The CCS Project Operator must show proof that there is a binding agreement among relevant parties that drilling or extraction that penetrate the confining layer above the sequestration zone is prohibited within the AOR.

    We understand the intent behind this provision is to ensure there is not movement of stored CO_2 out of the intended sequestration zone and above the storage complex or to the atmosphere. In oil and gas development, split estates, where the mineral estates and surface estate are owned by different parties are common. Different mineral estates underlying a single surface estate often exist at several different depths. For example, the Permian Basin consists of several basins, each with multiple formations lying at different depths, as illustrated in the figure below:



CO_2-EOR projects already take place in different formations that lie at different depths that are owned by different parties. Drilling through multiple formations is a technical challenge with engineered solutions. Drilling through multiple formations that may be owned by different parties requires drillers to set casing strings to prevent mixing of different zones. These same techniques safeguard freshwater aquifers from cross contamination as well as preventing the mixing of brackish water with freshwater. These same engineered solutions prevent the release of CO_2 from a CO_2-EOR project during the drilling and construction of wells.

Given the engineered solutions that are already available and in use, it is not necessary for relevant parties to meet an agreement that prevents drilling through one formation to access another formation – an activity that already occurs. While it is not possible to predict with certainty whether future technology will permit development of deeper formations that may underlie a CO_2-EOR project, past experience indicates that this is highly likely to occur. Owners of surface estates and mineral estates are aware of this likelihood and are reticent to take their property permanently out of production at any cost. Particularly, at the outset of a CCS Project. Assuming that a transition to a lower carbon intensity economy continues throughout this century, we do expect that relevant parties will be more amenable to reaching an agreement to prohibiting the advance of penetrations into other formations in the future. But it is not certain.

To account for these issues, and to still provide CARB the assurances it seeks, we suggest revising the language as follows:

C.9(c). Upon injection completion, the CCS Project Operator must show proof that there are sufficient safeguards in place to prevent leakage from the sequestration zone. These safeguards may include:

(1) A binding agreement among relevant parties that drilling or extraction that penetrate the confining layer above the sequestration zone are prohibited within the AOR;
(2) Enforceable regulatory or other legal mechanisms that require wells that penetrate the confining layer above the sequestration zone to prevent unauthorized mixing or loss of fluids from the sequestration zone and confining layer.

18. C.5.2(b)(2). After injection is complete, the CCS Project Operator must continue to conduct monitoring as specified in this section and the Executive Officer approved Post-Injection Site Care and Site-Closure Plan for a minimum of 100 years.

We understand that CARB proposes a 100-year post injection monitoring period to ensure that permanence can be demonstrated. Several authors have found that the critical monitoring period is 20-years post injection.[2] Beyond 20 years, the risk of a release from a subsurface reservoir declines asymptotically to near zero with time. We suggest that a performance standard approach is a preferred course of action. CCS Project Operators should have a range of options to demonstrate permanence, including:

- After 20 years, full closure of all penetrations into the sequestration zone, including monitoring wells, and the posting of a financial instrument accounting for the remaining 80 years of potential post closure liability, to ensure coverage in the event of an unforeseen event, e.g., a natural disaster, that results in a loss of some amount of CO_2 from the reservoir;
- An opt-out option transferring liability to the state and the use of a separate LCFS buffer account or some other financial instrument; or,
- Where permitted by state law, transfer liability to the state, e.g., as in Montana

[2] *See, e.g.*, Anderson, Steven T., (2017). Risk, Liability, and Economic Issues with Long-Term CO_2 Storage – A Review. *Natural Resources Research, 26(1),* 89, 93CO.