CARBON CAPTURE AND SEQUESTRATION PROJECT APPLICATION TEMPLATE

NOTE: The following non-mandatory template is provided as a convenient tool for entities applying for CCS Permanence Certification. CARB staff expects that due to the nature of the information required, most applicants using this template will find it easier to enter “See Attachment/Appendix (x)” in the appropriate section and attach the associated supporting documents in a zip file in the AFP Correspondence. This practice is expected and encouraged, as it will help CARB staff facilitate review of the application information.

The California Air Resources Board’s (CARB) Low Carbon Fuel Standard regulation, which appears at sections 95480 to 95503 of title 17, California Code of Regulations, is designed to reduce greenhouse gas emissions associated with the life cycle of transportation fuels used in California. CARB staff has prepared this document to describe the regulatory requirements in a user-friendly format. Unlike the regulation itself, this document does not have the force of law. It is not intended to and cannot establish new mandatory requirements beyond those that are already in the LCFS Regulation, nor can it supplant, replace or amend any of the legal requirements of the regulation. Conversely, any omission or truncation of regulatory requirements does not relieve entities of their legal obligation to fully comply with all requirements of the regulation.

SECTION A: General Project Information (CCS Protocol C.1.1.2(a))

Information entered on cover page

SECTION B: Primary Contact Information

Information entered on cover page

SECTION C: Project Eligibility (§95490(a))

1. Project Registration Category:
   ☐ Low Carbon Fuel Pathway ☐ Refinery Investment
   ☐ Innovative Crude ☐ Direct Air Capture
2. Project Reservoir Category:
   ☐ Saline Formation ☐ EOR Flood
   ☐ Depleted Oil and Gas Formation

SECTION D: Reporting Schedule

1. Please choose one of the following project reporting schedules (for LCFS crediting):

   ☐ Quarterly ☐ Annually

SECTION E: Co-Applicant Contact Information

1. Co-Applicant Business Name:
2. Business Telephone Number:
3. Co-Applicant Business Address:
4. City, State, ZIP Code:
5. Co-Applicant Contact Name:
6. Telephone Number/Email Address:

SECTION F: Purpose and Description of Business (CCS Protocol C.1.1.2(a)(1)-(2))

1. Provide a brief summary of the purpose of the project and description of the nature of the business:

SECTION G: Operator Activities and Permits

Provide a list of activities conducted by the operator which require it to obtain:

1. Permits under RCRA:
2. Permits under U.S. EPA UIC Program:
3. Permits under NPDES program under CWA:
4. Permits under PSD program under CAA:
5. Drilling permits:
6. Valid access agreements:
7. Encroachment permits under county or city guidelines:
8. Federal, state, or local air, water, or restricted lane use operating permits:

List all permits or construction approvals received or applied for and their status under any of the following programs:

9. Hazardous Waste Management program under RCRA:
10. U.S. EPA UIC program under SDWA:
11. NPDES program under CWA:
12. PSD program under CAA:
13. Nonattainment program under CAA:
14. NESHAPS preconstruction approval under CAA:
15. Dredge and fill permits under section 404 of Clean Water Act:
16. Other relevant environmental permits such as federal, state, county, or city permits:

SECTION H: Third Party Review (CCS Protocol C.1.1.1)

Sequestration Site Reviewer

1. Name of Reviewer:
2. List Specialty or Other Certifications:
3. License Number/State Issued:
4. Attach a resume or curriculum vitae of the Sequestration Site Reviewer and a statement of qualifications illustrating the reviewer's experience and education pertinent to evaluating the Certification.

5. List the reviewer's dates worked, company, position/title, brief description of duties performed, licenses, and education.

6. Provide a list of projects completed in the past five years in which the Sequestration Site Reviewer worked as the primary manager or contributed a significant amount of time including:
    - Projects related to CO_2-EOR completed for another company,
    - Projects studying or working in the same basin or reservoir as the applicant, and
    - Any other projects that seem applicable for this application.

    Include the start and end dates, project names, roles, and description.

7. Attach a signed attestation of the accuracy of the information provided in Sections H.1-6. See Appendix A of LCFS Guidance 19-07 for a template.

8. Provide a list of projects that the Sequestration Site Reviewer worked on for the CCS Project Operator that ended within five years of the application submittal. Include a list of each projects and a description of work that was completed for the CCS Project Operator, including the dates worked, company, and position/title.

9. Attached a signed attestation of the accuracy of the information provided in Section H.8. See Appendix B of LCFS Guidance 19-07 for a template.

10. Provide a list of projects that ended within five years of the application submittal that the employing company of the Sequestration Site Reviewer worked on for the CCS Project Operator, including:
    - A brief description of scope of work, dates of service, primary staff, project's revenue each year, total company review each year, and
    - A comparison of sum of past revenue from the CCS Project Operator to expected revenue from CCS Permanence Certification review.

11. Provide a company organizational chart, including management chain for the Sequestration Site Reviewer.

12. Attach a signed attestation of the truthfulness of the information provided in Sections H.10-11. See Appendix C of LCFS Guidance 19-07 for a template.

13. Attach a report from the Sequestration Site Reviewer that comments on each section of the application and their findings related to whether the section meets the requirements of the CCS Protocol and why.

14. Attach a certification from the Sequestration Site Reviewer that the data submitted for the Sequestration Site Certification Application is true, accurate, and complete. The reviewer must also certify that the Site-Based Risk Assessment submitted as part of the Sequestration Site Certification Application is accurate and complete, and the risks identified are either sufficiently monitored or sufficiently remediated in the Emergency and Remedial Response Plan.

CCS Project Reviewer

15. Name of Reviewer:
16. List Specialty or Other Certifications:
17. License Number/State Issued:
18. Attach a resume or curriculum vitae of the CCS Project Reviewer and a statement of qualifications illustrating the reviewer's experience and education pertinent to evaluating the Certification.

19. List the reviewer's dates worked, company, position/title, brief description of duties performed, licenses, and education.

20. Provide a list of projects completed in the past five years in which the CCS Project Reviewer worked as the primary manager or contributed a significant amount of time including:
    - Projects related to CO_2-EOR completed for another company,
    - Projects studying or working in the same basin or reservoir as the applicant, and
    - Any other projects that seem applicable for this application.

    Include the start and end dates, project names, roles, and description.

21. Attach a signed attestation of the truthfulness of the information provided in Sections H.15-20. See Appendix A of LCFS Guidance 19-07 for a template.

22. Provide a list of projects that the CCS Project Reviewer worked on for the CCS Project Operator that ended within five years of the application submittal. Include a list of each project and a description of work that was completed for the CCS Project Operator, including the dates worked, company, and position/title.

23. Attach a signed attestation of the truthfulness of the information provided in Section H.22. See Appendix B of LCFS Guidance 19-07 for a template.

24. Provide a list of projects that ended within five years of the application submittal that the employing company of the CCS Project Reviewer worked on for the CCS Project Operator, including:
    - A brief description of scope of work, dates of service, primary staff, project's revenue each year, total company revenue each year, and
    - A comparison of sum of past revenue from the CCS Project Operator to expected revenue from CCS Permanence Certification review.

25. Provide a company organizational chart, including management chain for the CCS Project Reviewer.

26. Attach a signed attestation of the truthfulness of the information provided in Sections H.24-25. See Appendix C of LCFS Guidance 19-07 for a template.

27. Attach a report from the CCS Project Reviewer that comments on each section of the application and their findings related to whether the section meets the requirements of the CCS Protocol and why.

28. Attach a certification from the CCS Project Reviewer that the CCS Project Certification Application plans are sufficiently robust that, in their professional judgment, the CCS Project is able to meet the permanence requirements for carbon sequestration.

SECTION I: Application Materials for Sequestration Site Certification (CCS Protocol C.1.1.2(b))

1. Site-Based Risk Assessment (CCS Protocol C.2.2)
    a. Based on the computational model, provide the likelihood that the fraction of CO_2 retained in the storage complex exceeds 99% over 100 year post injection.

    b. Risk Management Plan
        i. Classify the risk of the following scenarios according to Table 1 and provide justification for the classification. Also list the steps that will be taken to manage, monitor, avoid, or minimize the risks.

Table 1. Risk scenario classification.

	Insubstantial[1]	Substantial[1]	Catastrophic[1]
>5%[2]	Medium risk	High risk	High risk
1-5%[2]	Low risk	Medium risk	High risk
<1%[2]	Low risk	Medium risk	Medium risk

1. Injection, production, or monitoring well integrity failure;
2. Well Injection or monitoring equipment failure;
3. Fluid (e.g., CO_2 or formation fluid) leakage to the land surface and atmosphere;
4. A natural disaster with effects that could impact site operations (e.g. earthquake or lightning strike);
5. Induced seismic event; and
6. Other risks that could be reasonably anticipated. Include any risk scenarios identified as important but not included in the Emergency and Remedial Response Plan.

2. Geologic Evaluation (CCS Protocol C.2.3)
   a. Provide the following regional geologic information:
      i. A brief synopsis of the geological history of the CCS Project site;
      ii. Porosity, permeability, lithofacies, depositional environment, and geologic names and ages of formations;
      iii. Regional hydrogeology of the sequestration zone, including all available data pertaining to groundwater flow direction, flux, and flow patterns; and
      iv. Structural geology of the regional area, including faults and fault orientations, the presence and trends of folds, and whether these structures penetrate into the storage complex.
   b. Provide the following site-specific geologic and hydrogeologic information:

[1] Severity of potential consequences
[2] Probability of occurrence over 100 years

i. Depth interval of confining system and sequestration zone below ground surface;

ii. Depth interval of planned completion interval;

iii. Lithologic description from core or hand samples for both the confining system and sequestration zone, including petrology, mineralogy, grain size, sorting or grading, cementation and dissolution features, and lithofacies or geologic rock name; and

iv. Structural geology of the local area including faults and fault orientations, the presence and trends of folds, and whether these structures penetrate into the storage complex.

v. Thickness of:
    1. Confining system and sequestration zone;
    2. The confining layer(s) and sequestration reservoir (total);
    3. Any high permeability or porosity intervals in the sequestration zone (if applicable); and
    4. Planned perforated interval(s)

vi. Porosity, permeability, and capillary pressure of the:
    1. Sequestration zone; and
    2. Confining layer(s)

vii. Location of the completion interval

viii. Provide the calculations for the following properties of the sequestration zone and confining layer(s):
    1. Hydraulic conductivity;
    2. Specific storage; and
    3. Storage coefficient

c. Provide the following site-specific geomechanical and petrophysical information:
    i. Fracture/parting pressure of the sequestration zone and primary confining layer;

ii. Fracture gradients determined via step rate or leak-off tests performed in the wellbore;

iii. Rock compressibility (or similar estimation of measure of rock strength) for the confining layer(s) and sequestration zone;

iv. Rock strength and the ductility of the confining layer(s), and provide calculations;

v. Pore pressure or the measure of *in situ* fluid pressure;

vi. Formation temperature; and

vii. Estimation of the injection volume and maximum allowable injection rate and pressure such that neither the primary confining layer nor the sequestration zone hydraulically fracture during injection

d. Provide the results of injectivity or pump tests of the sequestration zone based on CO_2 reservoir flow modeling using information determined from step rate tests.

e. Provide the geologic characteristics of any secondary confining layer(s) above the primary confining layer and below the sequestration zone.

f. Provide the characteristics of any dissipation intervals above and below the target sequestration zone and confining layer.

g. Provide a full description of significant geologic structures, including faults and fractures, which intersect the storage complex.

h. Provide all data relevant to assessing the transmissivity of the features described in Section I.2.g.

i. Explain how the features described in Section I.2.g. will not interfere with containment.

j. Provide an evaluation of the seismic history of the proposed sequestration site, including the date, magnitude, depth, and location of the epicenter of seismic sources.

k. Provide a determination that the seismicity would not cause a catastrophic loss of containment, either by breaching the integrity of the well or the sequestration formation.

l. Provide a table of readily available information on the following items relating to freshwater aquifers and springs in the surface projection of the storage complex including:
    i. The numbers, thicknesses, and lithologies of freshwater aquifers including interbedded and low permeability zones;
    ii. Water quality such as TDS, alkalinity, pH, dissolved trace metals, and TOC;
    iii. The deepest depth of freshwater aquifers;
    iv. Whether any freshwater aquifers in the surface projection of the storage complex are currently accessed for human use; and
    v. Location and distance to nearest water supply well and nearest downgradient water supply, as well as any water wells and springs in the surface projection of the storage complex

m. Provide a table of readily available geochemical data on the following items relating to subsurface formations and formation fluids in and around the storage complex including:
    i. Reservoir fluid data for the sequestration zone such as TDS, dynamic viscosity, density, temperature, pH, and information on the potentiometric surface, if available;
    ii. Characteristics of any aquifers directly above or below the sequestration zone, if applicable, including TDS, temperature, and information on the potentiometric surface, if available; and
    iii. If applying for CO_2-EOR and/or depleted oil and gas reservoir sites, data such as oil gravity and viscosity, presence, concentrations, and specific gravity of non-hydrocarbon components in the associated gas (e.g. hydrogen sulfide) and any other compositional data as needed for modeling fluid interactions.

n. Provide the location and description of known mineral deposits or other natural resources above, beneath, or near the storage complex, including but not limited to, stone, sand, clay, gravel, coal, oil, and natural gas.

o. Describe and quantify any fluids injected or produced related to the CCS Project, in addition to the injection fluid.

p. Provide a management strategy for:
    i. The mitigation of potential unintentional release of production fluid;
    ii. Considering other injection, such as waste water disposal, in regards to pressure changes and the geomechanical response to such injection; and
    iii. Considering distant parameters, such as production or disposal, in the boundary conditions of the computational model parameters.

q. Provide the following site-specific maps and cross-sections:
    i. Geologic and topographic maps and cross-sections illustrating regional geology, hydrogeology, and geologic structure of the local area;

    ii. Maps and stratigraphic cross-sections indicating the general vertical and lateral limits of all freshwater aquifers, water wells, and springs within the surface projection of the storage complex, their positions relative to the storage complex, and the direction of shallow groundwater movement, where known;

    iii. Structural contour and isopach maps of the storage complex including all faults and fractures and any lateral containment features;

    iv. Stratigraphic columns or cross-sections of the regional basin showing lateral continuity of storage complex, as well as the lack of any significant compartmentalization or heterogeneity in the sequestration zone that could inhibit proposed injection volumes;

    v. Representative electric log to a depth below the sequestration zone and lower confining layer or dissipation interval(s) (or to a depth below the deepest producing zone if injection is for CO_2-EOR) identifying all geologic units, formations, freshwater aquifers, and oil or gas zones;

    vi. At least one cross-section of the storage complex to surface through the injection well(s);

    vii. Maps showing the locations of any seismic lines and cross-sections; and

    viii. Maps showing any known mineral deposits or natural resources within the surface projection of the storage complex.

r. Describe any accumulation of gas above, below, or within the storage complex, including but not limited to, the type of gas, location, depth, and areal extent on the surface.

s. Provide any additional information required by CARB that is necessary to complete the geological and hydrogeological site evaluation.

t. Formation Testing and Well Logging Plan (CCS Protocol C.2.3.1)
    i. Describe the logs, surveys, and tests that will be used to determine or confirm the depth, thickness, porosity, permeability, lithology, and salinity of all relevant geologic formations.

1. Will historical data be used for this requirement?
   ☐ Yes ☐ No

ii. Describe how whole cores or sidewall cores of the sequestration zone and primary confining layer, and formation fluid samples from the sequestration zone, will be taken during drilling and prior to well construction from a stratigraphic well or from the injection well.
   1. Will historical data be used for this requirement?
      ☐ Yes ☐ No
   2. Which will be taken: ☐ whole cores or ☐ sidewall cores?
   3. Will cores from nearby wells be used because core retrieval is not possible? ☐ Yes ☐ No
      a. If yes, describe why core retrieval is not possible and demonstrate that cores from nearby wells are representative of conditions at the well site.

iii. Describe how the downhole conditions (fluid temperature, pH, conductivity, reservoir pressure, fluid density, etc.) needed to support monitoring and computational modeling design will be collected. Justify the sufficiency of the data collected and the method by which it was collected and analyzed.
   1. Will historical data be used for this requirement?
      ☐ Yes ☐ No

iv. If geochemical data is to be used for monitoring, describe the site-specific procedure that will be used to separate leakage signal from background.
   1. Will historical data be used for this requirement?
      ☐ Yes ☐ No

v. Describe how step rate tests for each CO_2 injection well that is part of the CCS Project will be performed, and how the results of each test will be used to determine the fracture pressure of the sequestration zone and primary confining layer.
   1. Will historical data be used for this requirement?
      ☐ Yes ☐ No

vi. Select which transient analysis test(s) will be used to determine hydrogeologic characteristics of the sequestration zone:
   ☐ A pressure fall-off test
   ☐ A pump test
   ☐ Injectivity tests

1. Will historical data be used for this requirement?
   ☐ Yes ☐ No

vii. Describe how the tests used in Section I.2.t.vi. are designed to determine the injectivity of the sequestration zone to set operating limits for CO_2 injection rates and volumes.

viii. Describe how any additional physical and chemical characteristics of the sequestration zone and confining system which are needed to augment other information will be determined or calculated.

3. Storage Complex Delineation and Corrective Action Plan (CCS Protocol C.2.4)
   a. Computational Model
      i. Justify the following list of inputs used when designing the computational model, report on sensitivity analyses, and provide reasoning for all simplifications selected:
         1. Regional and site-specific geology, such as stratigraphy, formation lithology, elevation, thickness, and structural geology (including faults, folding, fractures);

         2. Reservoir conditions including hydrogeologic conditions such as intrinsic and relative permeabilities, porosity, capillary pressure, formation compressibility, water saturation, CO_2 saturation, and storativity, and reservoir fluid properties such as brine or hydrocarbon viscosity, density, composition or salinity, and hydrocompressibility;

         3. Geomechanical information on fracture pressure and gradient in the sequestration zone and confining layer(s), as well as any geomechanical processes or models that are incorporated into the storage complex delineation effort based on initial site characterization efforts;

         4. Existing and proposed operational and monitoring data, including the location of injection and/or extraction wells, fluid injection and withdrawal rates, bottom-hole pressure measurements, fluid characterization, inputs from monitoring systems (as recorded in, e.g., verification wells), CO_2 saturations and injected volumes, the location and number of injection, production, and monitoring wells, and well construction details (e.g., perforated intervals, etc.);

         5. Computational model parameters such as initial conditions (e.g., fluid composition and distribution, etc.) within the domain at the beginning of the model run, time steps and a justification for the selection, vertical and horizontal gridding design and a justification that they are fit-to-purpose, and

other model design parameters; and

6. Any other models, model parameters, and/or general assumptions that are incorporated or considered for the CCS Project and storage complex delineation based on site-specific conditions.

ii. If injecting into depleted reservoirs or CO_2-EOR operations, specify the assumptions made about the CO_2-fluid interactions (e.g., “black oil” or compositional model) and justify the selected approaches.

iii. Indicate the range of parameter values possible for the site and provide a justification for each particular parameter that is not directly measured in the field or the laboratory. Also, document the probability and statistical methods of distributing attributes and perform sensitivity analyses.

iv. Document and justify any simplifications made when considering the data collected to comply with the site characterization requirements in the storage complex delineation model.

v. Document which equations of state and constitutive relationships were derived from equilibrium phase relationships and empirically based approximations, respectively.

vi. State model orientation and gridding parameters, including the spatial temporal domains, grid spacing and gridding routine, coordinate system, horizontal datum, and the physical properties and assumptions used to define the domain boundaries.

vii. Describe and justify the method and assumptions used to history match the pressure distribution.

viii. Describe the possible impact of any geologic heterogeneities, other discontinuities, or data quality on model predictions.

ix. Describe the model’s detectable response to potential leakage through faults, fractures, and artificial penetrations.

x. Describe the implications of uncertainties in input data to the model predictions after performing sensitivity analyses on model input parameters.

xi. Demonstrate that the computer code(s) has been validated for use in peer-reviewed literature.

xii. Will the code(s) be available to CARB and CCS Project Operators the entire time during CARB's review of the application?

☐ Yes ☐ No

1. If no, list the periods of time when the code(s) would not be available for review.

xiii. Describe how the code(s) demonstrates the capability to:

1. Predict the evolution of the three-dimensional geometry of the CO_2 plume under reservoir conditions at the site during injection and post-injection;

2. Support the risk assessment by allowing the evaluation of the response of key geological formations, both within and above the storage complex, to CO_2 leakage response;

3. Support assessment of geomechanical response to pressure and fluid change during injection, especially with regard to risk of induced seismicity;

4. Provide a reliable timeline showing plume extent modeling and pressure equilibration; and

5. Support comparison of the modeled response to the reservoir response during monitoring.

xiv. Demonstrate that the computer code(s) is appropriate for the CCS Project through either successful application in a similar setting leading to successful history matching, comparison of a new code against a proven code to show reasonable match, or sensitivity studies showing that the code reproduces the relevant physics properly.

xv. Demonstrate that the code(s) properly manages key properties of the reservoir fluid system, including three-dimensionally heterogeneous formations, characteristic-curve hysteresis, and residual phase trapping.

xvi. If using a non-peer-reviewed independently developed or untested code, provide evidence that the developer validated the model's appropriateness by modeling validated test cases of problems with similar physics found in the literature.

b. Plume Extent Modeling Results

i. Provide the attributes of the code(s) used to create the computational model(s), including the code name, version, name of the developing organization, and full accounting of or reference to the model governing equations, scientific basis, and simplifying assumptions.

ii. Describe the model domain, such as the model's lateral and vertical extents, geologic layer thickness, and grid cell sizes, as presented on maps and cross-sections.

iii. List all equations of state used for all modeled fluids (groundwater, CO_2).

iv. List any constitutive relationships used, such as relative-permeability saturation relationships, and how they were determined.

v. Provide the model results, including prediction of the free-phase CO_2 plume extent and elevated pressure over the lifetime of the CCS Project. Present the results in contour maps, cross sections, and/or graphs showing the CO_2 plume extent and elevated pressure as a function of time. Include the outcome of parameter sensitivity analysis and model calibration.

c. Describe the minimum fixed frequency at which the CCS Project Operator will reevaluate the extent of the plume and a justification for the proposed reevaluation frequency.

d. Describe how monitoring and operational data (e.g., injection rate and pressure) will be used to inform a plume extent reevaluation.

e. Describe the methods for the identification of all artificial penetrations that either penetrate the storage complex or are within the surface projection of the storage complex and how these penetrations will be evaluated to determine whether corrective action is needed.

f. Describe the proposed corrective action for unplugged or improperly or insufficiently plugged wells that either penetrate the storage complex or are within the surface projection of the storage complex.

g. Describe what corrective action will be performed prior to injection, how corrective action will be adjusted if there are any changes in the storage complex delineation or injection operation, and how site access will be guaranteed for future corrective action.

h. Describe the schedule of corrective action activities that minimizes risk to public health and environment.

i. List any criteria, site-specific or otherwise, that will trigger a CO_2 plume extent reevaluation prior to the next scheduled reevaluation.

4. Baseline Testing and Monitoring Plan (CCS Protocol C.2.5(a))
   a. Describe the frequency and spatial distribution of baseline data collection.

   b. Explain how the baseline data collected is sufficient to track the three-dimensional evolution of the CO_2 plume, and is capable of being used for history matching the computational model and for comparison to levels during and after the operational phase of the CCS Project.

   c. Provide an evaluation of any property of the storage complex, groundwater, overburden, or surface projection of the storage complex that is shown by the risk assessment to potentially be impacted by injection operations.

   d. If deemed necessary, describe the approaches used to separate CO_2 leakage signals from natural changes arising from natural background variability at daily, seasonal, or long duration trends. If deemed unnecessary, explain why.

   e. Describe the tools used for baseline testing, and for each method provide the process by which the survey can be accurately repeated in terms of location and instrumentation.

5. Well Construction Plan (CCS Protocol C.3.1(b))
   a. Casing and cementing requirements
      i. Demonstrate that all well materials are compatible with fluids with which the materials may be expected to come into contact.

      ii. Demonstrate that the well materials meet or exceed standards developed for such materials by API, ASTM International, or comparable standards acceptable to CARB.

      iii. Describe how the casing and cementing requirements consider the following factors in the design to prevent the movement of fluids out of the sequestration zone and above the storage complex:
         1. Depth to the sequestration zone;

         2. Injection pressure, external pressure, internal pressure, and axial loading;

         3. Hole size;

         4. Size and grade of all casing strings (wall thickness, external diameter, nominal weight, length, joint specification, and

construction material);

5. Corrosiveness of the CO_2 stream and formation fluids;

6. Downhole temperatures;

7. Lithology of sequestration and confining layer(s);

8. Type or grade of cement and cement additives; and

9. Quantity, chemical composition, and temperature of the CO_2 stream.

iv. If not cementing at least one long string casing which extends to the sequestration zone by circulating cement to the surface in one or more stages because cementing to surface will comprise the integrity of the well or confining layer(s), explain the alternative proposed method of cementing and why this particular method was chosen.

v. Demonstrate that the alternative method described in Section I.5.a.iv. follows best practices that meet or exceed standards developed for such methods and materials by API, ASTM International, or comparable standards acceptable to CARB.

vi. Demonstrate that the cement and cement additives are of sufficient quality and quantity to maintain integrity over the design-life of the CCS Project.

vii. Describe how the technology used to verify the integrity and location of the cement is capable of evaluating cement quality radially and identifying the location of channels to ensure against the likelihood of an unintended release of CO_2 from the sequestration zone above the storage complex.

viii. Demonstrate how the cement and cement additives are compatible with the CO_2 stream and formation fluids within the sequestration zone.

b. Tubing and packer requirements

i. Demonstrate that the tubing and packer materials used in the construction of each CCS Project well are compatible with fluids with which the materials may be expected to come into contact.

ii. Demonstrate that the tubing and packer materials meet or exceed standards developed for such materials by API, ASTM

International, or comparable standards acceptable to CARB.

iii. Describe the location where fluids will be injected through tubing with a packer set within the long string casing. If the location is not within or below the primary confining layer, provide a justification of the proposed injection location.

iv. Describe how the tubing and packer requirements considers the following factors:
    1. Depth of setting;
    2. Characteristics of the CO_2 stream (chemical content, corrosiveness, temperature, and density) and formation fluids;
    3. Maximum proposed injection pressure;
    4. Maximum proposed annular pressure;
    5. Proposed injection rate (intermittent or continuous) and volume and/or mass of the CO_2 stream;
    6. Size of tubing and casing; and
    7. Tubing tensile strength, burst, and collapse pressures.

c. Wellhead and valve requirements
    i. Demonstrate that all CCS Project wells are equipped with wellheads, valves, piping, and surface facilities that meet or exceed design standards developed for such materials by API, ASTM International, or comparable standards acceptable to CARB.

    ii. Demonstrate that all piping, valves, and facilities must meet or exceed design standards for the maximum anticipated allowable injection pressure, and are maintained in a safe and leak-free condition.

    iii. Demonstrate that all ports on the wellhead assembly above the casing bowl of injection wells are equipped with valves, blind flanges, or similar equipment.

    iv. Demonstrate that wells are equipped with valves to provide isolation of the wells from the pipeline system and to allow for entry into the wells.

6. Pre-Injection Testing Plan (CCS Protocol C.3.2(b))
    a. If pilot holes are drilled as part of the CCS Project, describe how deviation checks will be logged during drilling of all holes constructed by drilling a pilot hole that is enlarged by reaming or another method. Describe how the interval frequency used is sufficient to determine the location of the borehole and to ensure that vertical avenues for fluid movement in the form of diverging holes are not created during drilling.

    b. Describe the series of tests that will be used to evaluate the integrity of the cement bond.

    c. Describe the series of tests that will be used to demonstrate the internal and external mechanical integrity of injection wells, which must include an annulus pressure test or a radioactive tracer survey, a temperature, noise, or oxygen activation log, and a casing inspection log.

    d. Describe any alternative methods that will be used that provide equivalent or better information.

    e. Describe how the fluid temperature, pH, conductivity, and reservoir pressure of the sequestration zone will be determined and recorded.

    f. Describe how the following information concerning the sequestration zone and confining layer(s) will be determined or calculated:
        i. Fracture pressure;

        ii. Other physical and chemical characteristics of the sequestration zone and confining layer; and

        iii. Physical and chemical characteristics of the formation fluids in the sequestration zone.

    g. Describe how the tests to determine hydrogeologic characteristics of the sequestration zone will be conducted.

7. Well Operating Plan (CCS Protocol C.3.3(a))
    a. Provide a map showing the injection facilities.

    b. Provide the maximum anticipated surface injection pressure (pump pressure) and daily rate of injection, by well.

    c. Describe the monitoring schedule and system or method to be utilized to ensure that no damage is occurring to the well or associated surface facilities and that all injection fluid is confined to the sequestration zone.

d. Describe the method of injection.

e. Describe the water treatment process for water injected during water alternating gas methods for CO_2-EOR purposes.

f. Provide the planned injection pressure.

    i. If the injection pressure in Section I.7.f. is greater than 80 percent of the fracture/parting pressure of the sequestration zone, explain why injecting below 80 percent of the fracture/parting pressure is not feasible, and why an alternative pressure must be used. Demonstrate that the method follows best practices that meet or exceed standards developed for such methods and materials by API, ASTM International, or comparable standards acceptable to CARB.

g. Describe the fluid that will be used to fill the annulus between the tubing and the long string casing.

8. Testing and Monitoring Plan (CCS Protocol C.4.1)
    a. Mechanical Testing Plan
        i. Select which of the following will be used to demonstrate internal mechanical integrity:
        ☐ An annulus pressure test
        ☐ A radioactive tracer survey
        ☐ An alternative test approved by CARB, described below:

        ii. Select which of the following will be used to demonstrate external mechanical integrity:
        ☐ A temperature log
        ☐ A noise log
        ☐ An oxygen activation log
        ☐ A radioactive tracer survey
        ☐ An alternative test approved by CARB, described below:

            1. Describe the planned schedule for demonstrating external mechanical integrity.

        iii. Describe the accuracy to which the gauges used in mechanical integrity demonstration will be calibrated to, as well as a proposed calibration schedule.

        iv. Identify whether any other testing requires greater accuracy than what was given in Section 8.a.iii., and what accuracy those tests require.

b. Emissions Monitoring Plan
    i. Describe how the CO_2 stream will be analyzed to yield data representative of its chemical and physical characteristics, including analysis frequency.

    ii. Describe where the injectate fluid samples will be collected from, and demonstrate that that point provides a sample that is representative of the composition of the injectate. Include any calculations required for complex systems.

    iii. Describe how the flow rate of the injection stream will be measured and monitored.

    iv. Describe how continuous measurement will be taken of the fluid flow rate, composition, and density.

    v. Describe how meter readings will be temperature and pressure compensated such that the meter output is set to standard reference temperatures and pressures.

    vi. Justify the placement of the project's flow meters.

    vii. Describe how continuous measurement will be taken of the fluid composition and density, including a description of whether the sample point is upstream of any mixing of new and recycled CO_2.

    viii. Describe how ownership transfer will be clearly documented for CO_2 transferred (third-party injection activity).

    ix. Describe how continuous measurement will be taken of the injection pressure at the wellhead and downhole.

    x. Select which of the following methods will be used for corrosion monitoring of well materials:
    ☐ Analyzing corrosion coupons of the well construction materials placed in contact with the CO_2 stream
    ☐ Routing the CO_2 stream through a loop constructed with the material used in the well and inspecting materials in the loop
    ☐ Performing casing inspection logs
    ☐ Using an alternative method approved by CARB, described below:

xi. Describe the planned procedure and schedule for pressure fall-off tests.

   1. If the procedure and schedule in Section I.8.b.xi. is not a pressure fall-off test of each well at least once every five years, describe the desired alternative test method and/or schedule, why fall-off tests are inappropriate, and how the proposed alternative method will provide data equivalent to fall-off tests.

   2. Demonstrate that the method in Section I.8.b.xi.1. follows best practices that meet or exceed standards developed for such methods and materials by API, ASTM International, or comparable standards acceptable to CARB.

xii. Inspection and Leak Detection Plan

   1. Describe the procedure that will be followed for quarterly inspection of all wellheads, valves, and piping, employing effective gas leak detection technology.

   2. Describe the procedure that will be followed for bi-annual testing of al surface and subsurface safety valves to ensure ability to hold anticipated pressure.

   3. Describe the procedure that will be followed for annual testing of the master valve and wellhead pipeline isolation valve for proper function and verification of the valve's ability to isolate the well.

   4. Describe how the wellhead assembly and attached pipelines for each of the injection wells used in association with the CCS Project will be inspected. Include the surrounding area within a 100-foot radius of the wellhead in the inspection.

   5. Describe how the gas leak detection technology used takes into account detection limits, remote detection of difficult to access locations, response time, reproducibility, accuracy, data transfer capabilities, distance from source, background lighting conditions, local ecology, geography, and meteorology.

   6. Describe how testing of surface equipment operational integrity is conducted in accordance with API Recommended Practice 14B, or equivalent.

xiii. Describe the proposed method for periodic monitoring of pressure and/or composition above the storage complex. Explain the rationale and leakage detection threshold of the selected monitoring method.

xiv. Provide the location and number of monitoring wells for the CCS Project. Provide rationale for the wells based on specific information about the CCS Project, including injection rate and volume, geology, the presence of artificial penetrations, and other factors.

xv. Describe the monitoring frequency and spatial distribution of monitoring wells based on any modeling results.

xvi. Demonstrate that the Testing and Monitoring Plan is suitable to provide data sufficient to validate the computational model and ensure that the CO_2 plume will remain inside the storage complex at least until the end of the post-injection site care and monitoring period.

xvii. Provide an inventory of the testing and monitoring methods along with a description of the suitability of the methods to provide site-specific, risk-based data.

xviii. Describe how the monitoring plans and methods are designed to detect and quantify any CO_2 leakage, including plans that accomplish the following:

1. Specify the process and detection threshold at which leakage from any potential pathway, from reservoir to surface, will be detected and quantified;

2. Use maps and computational modeling to show how measurements and computational models will be used to trigger a finding of leakage; and

3. Describe how monitoring data will be used to determine and quantify any CO_2 leakage, and show that mitigation attempts have been effective.

xix. Describe the surface monitoring techniques used to detect potential shallow subsurface or atmospheric CO_2 leakage.

xx. Describe the methods used to measure and quantify CO_2 leakage from the storage complex. Provide an estimation of the precision and accuracy of those methods.

xxi. Provide the frequency at which data will be acquired.

xxii. Describe the record keeping plan.

xxiii. Provide the frequency at which instrument calibration activities will occur.

xxiv. Describe the QA/QC provisions on data acquisition, management, and record keeping that ensures it is carried out consistently and with precision.

xxv. Describe the role of individuals performing each specific monitoring activity.

xxvi. Describe the methods used to measure and quantify the following data:

1. Quantity of CO_2 emitted from the capture site;

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

3. Quantity of CO_2 injected into each CCS Project well.

xxvii. Describe any additional monitoring required by CARB, which is necessary to support, upgrade, and improve computational modeling of the CO_2 plume extent.

c. Monitoring, Measurement, and Verification of Containment Plan

i. Describe how the free-phase CO_2 plume extent will be monitored, including which methods will be used.

ii. Describe how the elevated pressure of the CO_2 plume will be monitored, including which methods will be used. Provide an estimate of the site-specific quality of detection for each chosen method.

iii. Select which method(s) will be used to detect atmospheric CO_2 leakage. Describe specifically how the method(s) will be used at the sequestration site.

☐ Optical sensors
☐ Infrared (IR) open-path detectors
☐ Forward looking infrared (FLIR) cameras
☐ Multi-spectral imaging
☐ Atmospheric tracers, including natural and injected chemical compounds

☐ Eddy covariance flux measurement techniques
☐ Alternative methods approved by CARB, described below:

iv. Describe the methods that will be used to monitor all wells that intersect the storage complex at depth.

v. Describe the methods that will be used to conduct annual vegetation surveys to measure potential vegetative stress resulting from elevated CO_2 in soil.

vi. Select which of the following methods will be used to geochemically monitor the soil and vadose zone if deep subsurface or atmospheric monitoring suggests that atmospheric CO_2 leakage may occur or has occurred. Describe specifically how the method(s) will be used at the sequestration site.
☐ Flux accumulation chamber methods
☐ Active sample collection methods including shallow monitoring wells, ground probes, and permanent soil gas probes
☐ Passive sample collection methods
☐ Alternative methods approved by CARB, described below:

vii. Describe how a permanent, downhole seismic monitoring system will be deployed and maintained in order to determine the presence or absence of any induced micro-seismic activity associated with all wells and near any discontinuities, faults, or fractures in the subsurface.

viii. Identify which seismic network/system will be continuously monitored for indication of an earthquake of magnitude 2.7 or greater occurring within a radius of one mile of injection operations.

ix. Estimate the precisions and accuracy of the methods used to measure and quantify CO_2 leakage from the storage complex.

9. Well Plugging and Abandonment Plan (CCS Protocol C.5.1)
   a. Describe the tests or measures that will be used for determining bottom-hole pressure.

   b. Describe the testing methods that will be used to ensure external mechanical integrity.

   c. List the type and number of plugs to be used.

d. Describe and depict the placement of each plug, including the elevation of the top and bottom of each plug.

e. Describe the type, grade, and quantity of materials to be used in plugging. Demonstrate that the material is compatible with the CO_2 stream.

f. Describe the method of plug placement.

10. Post-Injection Site Care and Site Closure Plan (CCS Protocol C.5.2)
    a. Provide the pressure differential between pre-injection and predicted post-injection pressures in the sequestration zone.

    b. Provide the predicted timeframe in which pressure is expected to reach a stable level.

    c. Provide a depiction of the predicted three-dimensional extent of the free-phase CO_2 plume and associated elevated pressure at the time of site closure as demonstrated in the final validated computational model.

    d. Describe the post-injection monitoring location, methods, and proposed frequency.

    e. Provide a proposed schedule for submitting post-injection site care monitoring results to CARB.

11. Emergency and Remedial Response Plan (CCS Protocol C.6)
    a. Describe the actions that will be taken in event of the following emergency scenarios at the site that have the potential to endanger public health or the environment during construction, operation, and post-injection site care periods:
        i. Injection, production, or monitoring well integrity failure;

        ii. Well injection or monitoring equipment failure;

        iii. Fluid (e.g., CO_2 or formation fluid) leakage to the land surface and atmosphere;

        iv. A natural disaster with effects that could impact site operations (e.g. earthquake or lightning strike);

        v. Induced seismic event; and

        vi. Other emergency scenarios, described below, including site-specific scenarios identified in the Site-Based Risk Assessment:

b. Describe the potential consequences of the risk scenarios listed in Section I.11.a.

c. Describe the local resources and infrastructure that may be impacted as a result of an emergency at the CCS Project site.

d. Describe any steps needed to identify and characterize each potential risk scenario listed in Section I.11.a.

e. List the site personnel, CCS Project personnel, and local authorities, and their contact information.

f. List any special equipment needed in event of an emergency.

g. Provide a site-specific emergency communications plan, including a public and media communications liaison.

h. Provide the timeline for review of the Emergency and Remedial Response Plan.

12. Financial responsibility demonstration (CCS Protocol C.7)

a. Select the financial responsibility instrument(s) being used to demonstrate financial responsibility:
☐ Trust Funds
☐ Surety Bonds
☐ Letter of Credit
☐ Insurance
☐ Self-Insurance (i.e., Financial Test and Corporate Guarantee)
☐ Escrow Account
☐ Any other instrument(s) satisfactory to CARB, described below:

b. Describe how the financial responsibility instrument(s) is sufficient to cover the cost of corrective action, well plugging and abandonment, post-injection site care and site closure, and emergency and remedial response.

c. If using a third-party instrument to demonstrate financial responsibility, provide proof that the third-party providers either have passed financial strength requirements based on credit ratings, or has met a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.

d. If using self-insurance to demonstrate financial responsibility, please provide proof of:
    i. A tangible net worth of an amount approved by CARB;

ii. A net working capital and tangible net worth each at least six times the sum of the current well plugging, post-injection site care and site closure cost;

iii. Assets located in the United States amounting to at least 90 percent of total assets or at least six times the sum of the current well plugging, post-injection site care and site closure cost; and

iv. One of the following:
    1. A bond rating test of AAA, AA, A, or BBB as issued by Standard & Poor's;

    2. A bond rating of Aaa, Aa, A, or Baa as issued by Moody's; or

    3. Meeting all of the following five financial ratio thresholds:
        a. A ratio of total liabilities to net worth less than 2.0;

        b. A ratio of current assets to current liabilities greater than 1.5;

        c. A ratio of the sum of net income plus depreciation, depletion, and amortization to total liabilities greater than 0.1;

        d. A ratio of current assets minus current liabilities to total assets greater than -0.1; and

        e. A net profit (revenues minus expenses) greater than 0.

e. If unable to meet corporate financial test criteria, describe how the corporate parent meets the financial test requirements to arrange a corporate guarantee.

f. For all other financial responsibility instruments, provide proof of the instrument for CARB review.

g. Provide a detailed written estimate, in current dollars, of the cost of performing corrective action on all wells that either penetrate the storage complex or are within the surface projection of the storage complex, plugging the well(s), post-injection site care and site closure, and emergency and remedial response.

13. Legal understanding demonstration (CCS Protocol C.9)
    a. Provide proof of exclusive right to use the pore space in the sequestration zone for storing CO_2 permanently.

    b. Provide proof that there is binding agreement among relevant parties that drilling or extraction that penetrate the storage complex are prohibited to ensure public safety and the permanence of stored CO_2.

14. Other (CCS Protocol C.1.1.2(b)(3)(C))
    a. List all other attached plans, demonstrations, results, etc., that are required by CARB in order to evaluate the application for Sequestration Site Certification.

SECTION J: Application Materials for CCS Project Certification (CCS Protocol C.1.1.2(d))

1. Updates to Information or Plans from C.1.1.2(b) (CCS Protocol C.1.1.2(d)(1))
    a. List all updated plans.

2. Formation Testing and Well Logging Report (CCS Protocol C.2.3.1(l))
    a. Was this report prepared by an experienced log analyst? ☐ Yes ☐ No
    b. Provide the temperature vs. depth and hydrostatic pressure profiles which were created using the well logging results.

    c. Provide the results of all downhole analyses and any laboratory results on samples, including quality assurance samples (e.g., blanks, duplicates, matrix spikes).

    d. Report the results of all step rate tests for each CO_2 injection well.

    e. Provide the maximum allowable injection pressure for the CCS Project determined from the step rate tests such that injection will not initiate or propagate faults or fractures in the sequestration zone or confining layer.

    f. Discuss how the calculated fracture pressure compares with data from core tests or other wells in the area, if available.

    g. Provide the results of each test and log that were conducted as part of the Formation Testing and Well Logging Plan, and any supplemental data.

    h. Provide an interpretation of the tests and logs, including any assumptions, and the determination of the sequestration zone and confining system characteristics, including porosity, permeability, lithology, thickness, depth, and formation fluid salinity of relevant geologic formations.

i. Discuss any changes in interpretation of site stratigraphy based on formation testing and well logs.

j. Describe any alternative methods used that provide equivalent or better information.

k. Demonstrate that the information collected is consistent with other available site characterization data submitted with the Permanence Certification and that the data support other assessments of stratigraphy and formation properties.

3. Updated Storage Complex Delineation and Computational Modeling Results (CCS Protocol C.2.4.2)
    a. Provide an updated model that uses all additional characterization and pre-injection testing data.

4. Corrective Action Report (CCS Project C.2.4.3(c))
    a. Provide a tabulation of each deficient well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information CARB may require.

    b. For each deficient well identified to require corrective action, provide a casing diagram as both a graphical diagram and as a flat file data set meeting the following requirements:
        i. Include the following data to the extent known:
            1. Operator name, lease name, well number, and API number of the well;
            2. Ground elevation from sea level;
            3. Reference elevation (i.e. rig floor or Kelly bushing);
            4. Base of freshwater;
            5. Sizes, grades, connection type, and weights of casing and tubing;
            6. Depths of casing shoes, stubs, and liner tops;
            7. Depths of perforation or other completion intervals, water shutoff holes, cement port, cavity shots, cuts, casing damage, and type and extent of any debris left in well, and any other feature that influences flow in the well or may compromise the mechanical integrity of the well;
            8. Information regarding associated equipment such as subsurface safety valves, packers, and gas lift mandrels;
            9. Diameter and measured and true vertical depth of wellbore;
            10. Wellbore path that includes inclination and azimuth measurements;
            11. Cement plugs inside casings, including top and bottom of cement plug, with measuring method indicated;

12. Cement fill behind casings, including top and bottom of cement fill, with measuring method indicated;
13. Type and density of fluid between cement plugs;
14. Depths and names of the formations, zones, and sane markers penetrated by the well, including the top and bottom of the zone where injection will occur;
15. All steps of cement yield and cement calculations performed;
16. All information used to calculate the cement slurry (volume, density, yield), including but not limited to, cement type and additives, for each cement job completed in each well; and
17. When multiple boreholes are drilled, all of the information listed in this section for the original hole and for any subsequent redrilled or sidetracked wellbores.

ii. Include any additional information that CARB may require.

5. Baseline Testing and Monitoring Report (CCS Protocol C.2.5(d))
   a. Assess the impact of baseline site characteristics (e.g., downhole pressure, sequestration zone fluid chemistry, soil-gas composition, vegetation type and density, and fresh and overburden water chemistry and pressure) on operational and long term monitoring.

   b. Provide the sampling locations in map form along with dates sampled, and demonstrate that the locations sampled represent a reasonable grid size.

   c. Demonstrate that the locations sampled represent potential point sources and that those locations will serve as a good baseline to compare to future monitoring data.

   d. Demonstrate that seasonal and diurnal variations in CO_2 levels have been captured and describe the variability in the data for future reference and to compare to operational and post-operational modeling.

   e. Describe the sampling and analytical methods used, including detection limits.

   f. Provide the results presented as concentrations and fluxes in tabular and graphic form, including quality assurance (QA) samples and analyses.

   g. Provide the methods and results of any regression analyses.

   h. Provide the methods and results of any ecological modeling or sensitivity analysis performed, including input data and outputs.

6. Well Construction and Pre-Injection Testing Report (CCS Protocol C.3.1(c), C.3.1(d), C.3.2(c))
    a. Describe any changes to casing and/or cement materials or designs that deviate from the original casing and cementing program in the Well Construction and Pre-Injection Testing Plan.

    b. Describe any changes to the tubing and packer used in the wells that deviate from the original materials proposed in the Well Construction and Pre-Injection Testing Plan.

    c. If pilot holes were drilled as part of the CCS Project, interpret the deviation checks that were logged during drilling of al holes constructed by drilling a pilot hole that is enlarged by reaming or another method.

    d. Interpret the results of the series of tests used to evaluate the geological and hydrological characteristics of the wellbore.

    e. Interpret the results of the casing inspection logs to evaluate the integrity of the cement bond.

    f. Interpret the results of the series of tests used to demonstrate the internal and external mechanical integrity of injection wells.

    g. Interpret the results of any alternative methods that provide equivalent or better information.

    h. Provide the fluid temperature, pH, conductivity, and reservoir pressure of the sequestration zone.

    i. Provide the fracture pressure of the sequestration zone and confining layer(s).

    j. Provide information on other physical and chemical characteristics of the sequestration zone and confining layer that were investigated as part of the Pre-Injection Testing Plan.

    k. Provide information on the physical and chemical characteristics of the formation fluids in the sequestration zone that were investigated as part of the Pre-Injection Testing Plan.

    l. Provide the results of the tests to determine hydrogeologic characteristics of the sequestration zone investigated as part of the Pre-Injection Testing Plan.

7. Mechanical Integrity Tests Report (CCS Protocol C.4.2.1(a))
    a. Provide the following information relating to the mechanical integrity test results prepared by an experienced log analyst:
        i. Chart and tabular results of each log or test;
        ii. The interpretation of log results provided by the log analyst;
        iii. A description of all tests and methods used, along with justification;
        iv. The records and schematics of all instrumentation used for the tests and the most recent calibration of any instrumentation;
        v. The identification of any loss of mechanical integrity, evidence of fluid leakage, and remedial action taken;
        vi. The date and time of each test;
        vii. The name of the logging company and log analyst;
        viii. For any tests conducted during injection, operating conditions during measurement, including injection rate, pressure, and temperature;
        ix. A copy of the calibration certificate for the gauges used in demonstrating mechanical integrity; and
        x. Any other information relating to the mechanical integrity test results.
8. Other (CCS Protocol C.1.2(e))
    a. List all other attached reports, results, updated plans, demonstrations, etc., that are necessary to evaluate the application for CCS Project Certification.