Appendix B-2

Proposed Amendments to the Carbon Capture and Sequestration Protocol Under the Low Carbon Fuel Standard

Greenhouse Gas Quantification Methodology for Carbon Capture and Sequestration under the Low Carbon Fuel Standard

[Note: This version of the Proposed Regulation Order complies with Government Code section 11346.2 subdivision (a)(3). The proposed amendments are shown in underline to indicate additions and strikethrough to indicate deletions from the existing regulatory text. For ease of readability, CARB has also provided a version of the proposed amendments that can toggle between amendments in strikeout/underline and a “clean" version with amendments incorporated into the regulatory text, which can be found in the Word version of this Proposed Regulation Order.]



Greenhouse Gas Quantification Methodology for Carbon Capture and Sequestration ~~Protocol~~ under the Low Carbon Fuel Standard

~~August 13, 2018~~
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GREENHOUSE GAS QUANTIFICATION METHODOLOGY FOR CARBON CAPTURE AND SEQUESTRATION ~~PROTOCOL~~ UNDER THE LOW CARBON FUEL STANDARD

~~A. DEFINITIONS AND APPLICABILITY~~

~~1.~~ Chapter 1. Applicability and Definitions

1.1. ~~The~~ Applicability

(a) Carbon Capture and Sequestration (CCS) projects that meet the permanence certification requirements pursuant to Section C of the Geologic Carbon Storage Protocol (GCS Protocol) and applicable CCS provisions in sections 95489 and 95490 of the Low Carbon Fuel Standard regulation (title 17, California Code of Regulations (CCR) sections 95480-95503) must use the accounting approaches specified in this Greenhouse Gas Quantification Methodology for Carbon Capture and Sequestration (LCFS CCS QM) to generate Low Carbon Fuel Standard (LCFS) credits.

(b) This Methodology applies to CCS projects that:

(1) Capture CO_2 from industrial or direct air capture systems;

(2) Transport the captured CO_2 to a geologic carbon ~~dioxide (CO_2)~~storage (GCS) site;

(3) Inject and permanently sequester ~~it onshore, in either saline or depleted oil and gas reservoirs, or oil and gas reservoirs used for CO_2 enhanced oil recovery (CO_2-EOR). The CCS~~ in accordance with the GCS Protocol ~~applies to both new and existing CCS projects, provided the projects meet the requirements for permanence pursuant to section C of this protocol.~~; and

(4) Meet all monitoring, reporting, verification, and permanence requirements specified under the LCFS Regulation and the GCS Protocol.

~~2.~~1.2. Definitions and Acronyms

(a) Definitions: For purposes of this ~~document, the definitions in title 13, California Code of Regulations, section 95481 apply, except as otherwise specified in the document. The~~ Methodology the following definitions ~~also~~ apply ~~to this document~~:

~~(1)~~ ~~"Active life" or "operational life~~"Atmospheric CO_2 leakage" means the ~~operational phase~~intended or unintended release of stored CO_2 outside the storage complex to the surface and atmosphere. ~~a CCS project in which injection and, if applicable, production occurs. The term omits the monitoring and site care phase of the CCS project following injection completion.~~

~~(2) "Aqueous diffusion coefficient" is the magnitude of the molar flux through a surface per unit concentration gradient. Typical diffusion coefficients for organic compounds in aqueous solution range between 10^{-10} to 10^{-9} m^2/s.~~

~~(3) "Artificial penetration" means any man-made structures, such as wells or mines, which provide a flow path out of the sequestration zone or storage complex.~~

~~(4) "Assets" means all existing and all probable future economic benefits obtained or controlled by a particular entity.~~

~~(5) "Biogenic CO_2" refers to CO_2 produced from biomass.~~

~~(6) "Borehole" means a cylindrical hole cut into rock or soil by drilling. Also refers to the inside diameter of the wellbore wall (i.e., the rock face that bounds the drilled hole).~~

~~(7) "Bottom-hole pressure" means the pressure at the bottom of the wellbore within the sequestration zone. It may be measured directly with a downhole pressure transducer, or in some cases estimated from the surface pressure and the height and density of the fluid column.~~

~~(8)~~ "Brine" is water containing dissolved minerals and inorganic salts in solution, including sodium, calcium, or bromides. Water containing dissolved solids in excess of ~~100~~ 10 grams per liter (g/L) is classified as brine. Large quantities of brine are often produced along with oil and gas.

~~(9) "Brittleness" is a property of a rock in which failure under a load occurs by fracturing, rather than by plastic deformation.~~

~~(10) "Capillary pressure" means the pressure difference across the interface of two immiscible fluids (e.g., CO_2 and water).~~

~~(11) "Capillary entry-pressure" means the pressure that a non-wetting fluid (e.g. CO_2) must overcome to displace water held tightly by capillary forces in the pores of a rock or sediment.~~

~~(12) "Capture Facility Operator" means the operator responsible for the CCS capture facility.~~

~~(13)~~ "Carbon capture and sequestration (CCS)" means the processes of ~~concentrating~~capturing CO_2 present in flue ~~and/~~or exhaust gases~~, or~~ and direct air~~,~~ capture via chemical and/or physical separation methods, transporting the CO_2 to an injection site, and injecting and permanently sequestering the captured CO_2.

~~(14)~~ "Carbon dioxide equivalent" or "CO_2 equivalent" or "CO_2e" means the number of metric tons of CO_2 emissions with the same global warming potential as one metric ton of another greenhouse gas. ~~-~~For the purposes of the LCFS CCS ~~Protocol~~QM, global warming potential values listed in the CA-GREET model are used to~~-~~ determine~~-~~ the CO_2~~-~~ equivalent of GHG emissions.

~~(15) "Carbon intensity" has the same meaning as in 13, CCR, section 95481.~~

~~(16) "Casing" or "casing string" means a pipe or tubing of appropriate material (typically made of steel as used in oil and gas wells), of varying diameter and weight, lowered into a borehole during or after drilling in order to support the sides of the hole and thus prevent the walls from caving, to prevent the loss of drilling mud into porous ground, to prevent water, gas, or other fluid from entering or leaving the hole, or to allow conveyance of fluids to/from the surface from/to a specific location in the subsurface. "Long string casing" refers to the last, or longest, casing set in a well, set through the sequestration or production reservoir. "Surface casing" refers to the first string of casing that is set in a well, and varies in length from a few hundred to a few thousand feet.~~

~~(17) "Casing inspection logs (CIL)" are used to determine the presence or absence of corrosion in the long-string casing.~~

"CCS Project" means a project that captures CO_2 by an eligible entity specified in section 95490(a) of the Low Carbon Fuel Standard Regulation, transports the captured CO_2 to an injection site, and injects and permanently sequesters the captured CO_2 pursuant to the Geologic Carbon Storage Protocol.

~~(18) "Casing shoe" means the bottom of the casing string or the equipment run at the bottom of the casing string.~~

~~(19) "CCS capture facility" means any plant, building, structure, or stationary equipment that captures CO_2 generated from industrial processes, or the atmosphere.~~

~~(20)~~ "CCS Project GHG emissions" means the ~~"CCS project" means the overall CCS project operations, including those of the CCS capture facility and geologic sequestration site and~~GHG emissions from specified activities associated with a CCS Project.

~~(21)~~ "CCS Project Operator" means the ~~operator~~entity responsible for ~~the CCS project~~operating and managing all or a portion of CCS Project activities, including carbon capture, compression, transport, injection, and compliance with LCFS Regulation and GCS Protocol requirements.

~~(22)~~ "CO_2-enhanced oil recovery (CO_2-EOR)" means the injection into and storage of CO_2 in oil reservoirs contributing to the extraction of crude oil.

~~(23)~~ "CO_2 injection" means the process of injecting CO_2 into geologic reservoirs.

~~(24)~~ "CO_2 leakage" means any movement of stored CO_2 out of the ~~intended sequestration zone and out of the storage complex. "Atmospheric leakage" means the intended or unintended release of stored CO_2 outside the storage complex to the surface and atmosphere. "Subsurface leakage" means the vertical movement of stored CO_2 out of the storage complex that does not reach the atmosphere.~~storage complex.

~~(25) "CO_2 plume" means the physical extent underground, in three dimensions, of the free-phase and dissolved CO_2 stream.~~

~~(26)~~ "CO_2 stream" means CO_2 that has been captured from an emission source (e.g., a power plant~~), plus~~) or ambient air, and may contain incidental associated substances derived from the source materials and the capture process, and any substances added to the stream to enable or improve the injection process.

~~(27)~~ "CO_2 ~~separation~~supplier" means the ~~process~~entity that ~~separates~~captures the CO_2 ~~from produced oil, water,~~ and ~~natural gases~~ either provides it for ~~re-~~injection ~~in the subsurface~~ or ~~transfer off~~transport to the GCS site, or injects or transport the CO_2 to the GCS site. The CO_2 supplier may also be the CCS Project Operator~~The CO_2 supplier may also be the CCS Project Operator~~.

~~(28) "Completion interval" means the section of wellbore that has been prepared for production by creating channels between reservoir formation and the wellbore.~~

~~(29) "Computational model" means a mathematical representation of the injection project and relevant features, including injection wells, geology, and fluids present. For a CCS project, site-specific geological information is used as an input to a computational code, creating a computational model that provides predictions of subsurface conditions, fluid flow, and CO_2 plume and elevated pressure migration at that site. computational model includes all model input and predictions (i.e., outputs).~~

~~(30) "Confining pressure" means the combined hydrostatic and lithostatic stresses, or the total weight of the interstitial pore water and rock above a specified depth.~~

~~(31) "Confining system" means a multi-layered laterally extensive geologic formation, group of formations, or part of a formation, stratigraphically overlying the sequestration zone that exhibits low permeability and/or high~~

~~capillary entry-pressure (e.g. a clay-rich shale or mudstone) such that it impedes the upward migration of fluid(s). The "primary confining layer" refers to the confining layer directly above the sequestration zone. "Secondary confining layer" refers to any confining layer directly above a dissipation zone and above the storage complex.~~

~~(32) "Constitutive relationships" represent empirically based approximations used to simplify the real-world system and estimate unknowns. Examples include saturation-relative permeability relationships, interphase mass transfer relations, and solution reaction relations.~~

~~(33) "Corporate parent" means a corporation that directly owns at least 50 percent of the voting stock of the corporation that is; the latter corporation is deemed a subsidiary of the parent corporation.~~

~~(34) "Corrective action" means the use of California Air Resources Board-approved well remediation methods to ensure that any artificial penetrations within a storage complex do not serve as conduits for the movement of fluids out of the intended storage complex.~~

~~(35) "Corrosion" means the loss of metal due to chemical or electrochemical reactions that may cause loss of mass or thickness, cracking, or pitting of well components (casing, tubing, or packer).~~

~~(36) "Corrosion coupons" are small, pre-weighed, and measured pieces of metal made of the construction materials that are exposed to well fluids for a defined period, then removed, cleaned, and weighed to determine the corrosion rate. The coupon is made from the same material as the well's casing or tubing. The average corrosion rate in the well is calculated from the weight loss of the coupon.~~

~~(37) "Corrosion loops" are sections of tubing that are valved so that some of the injection stream is passed through a small pipe running parallel to the injection pipe at the surface of the well. These loops allow for monitoring and analysis of corrosion.~~

~~(38) "Current assets" means cash or other assets or resources commonly identified as those that are reasonably expected to be realized in cash, sold, or consumed during the normal operating cycle of the business.~~

~~(39) "Current liabilities" means the obligations whose liquidation is reasonably expected to require the use of existing resources properly classifiable as current assets or the creation of other current liabilities.~~

~~(40) "Darcy's law" is an equation that defines the ability of a fluid to flow through a porous medium such as rock. It relies on the fact that the amount of flow~~

~~between two points is directly related to the difference in pressure between the points, the distance between the points, and the interconnectivity of flow pathways in the rock between the points.~~

~~(41)~~ "Depleted oil and gas reservoir~~s~~" means ~~reservoirs~~any reservoir that do~~es~~ not currently produce oil or gas, and ~~are~~is considered to have no economically recoverable oil or gas ~~with~~using current technology.

~~(42) "Depositional environment" is a specific type of place on the surface of the earth in which certain chemical, biological, and physical characteristics affect the deposition of sediments. The three overarching types of depositional environment include continental, marginal marine, and deep marine.~~

~~(43) "Deviated well" means a well that is not drilled vertically for its whole length, or a well with an inclination designed to be other than zero degrees from vertical.~~

~~(44) "Dissipation interval" is a stratigraphic interval with hydrogeologic properties sufficient to attenuate pressure created by CO_2 or formation fluid migration along an unidentified leakage pathway through the confining system.~~

~~(45) "Downhole measurements" are measurements collected from within the wellbore or borehole, either while drilling or during well maintenance or operation. Downhole measurements are used to determine physical, chemical, and structural properties of formations penetrated by a drill hole.~~

~~(46) "Ductility" means the property of a rock by which the rock plastically deforms under a load, rather than breaking by fracturing.~~

~~(47) "Elevated pressure" means the fluid response to CO_2 injection such that the pressure rise creates a risk of CO_2 or brine leakage.~~

~~(A) In a normally pressured system, elevated pressure is defined as the pressure increase such that brine from the sequestration zone would be lifted above the storage complex if a conduit opened.~~

~~(B) If the sequestration zone is naturally overpressured, such that brine would be lifted above the storage complex prior to injection if a conduit opened, elevated pressure is defined as a 20-psi increase, unless otherwise adjusted based on site and risk characteristics.~~

~~(48) "Embodied GHG" means lifecycle greenhouse gas emissions associated with production and transport of process fuels and chemicals to the point of use (e.g., GHG from the production and transport of natural gas as process fuel to a refinery).~~

~~(49)~~ "Entrained CO_2" means CO_2 that remains in water, oil, or natural gas after the (oil, water, and natural gas) separation has taken place.

~~(50) "Equation of state" refers to an equation that expresses the equilibrium phase relationship between pressure, volume, and temperature for a particular chemical species.~~

~~(51) "Fluid" means liquid or gas.~~

~~(52) "Fluid pressure" means the measure of the potential energy per volume of fluid, based on force acting per unit area (psi or kPa).~~

~~(53) "Formation compressibility" is the relative volume change of a formation per unit pressure change.~~

~~(54) "Fracture pressure" or "parting pressure" is the pressure in the wellbore above which the injection of fluids will cause the rock formation to fracture hydraulically.~~

~~(55) "Fracture gradient" is the factor used to determine formation-fracturing pressure as a function of well depth in units of psi/ft.~~

~~(56) "Free-phase CO_2 plume" means the portion of CO_2 in supercritical, gaseous, or liquid phase, rather than as a dissolved component in native fluid (e.g., dissolved in brine), that occupies pore space within the sequestration zone.~~

~~(57) "Freshwater aquifer" means an aquifer that contains fewer than 10,000 mg/L total dissolved solids per the U.S. EPA Safe Drinking Water Act[1].~~

~~(58)~~ "Fugitive emissions" means unintentional leakage of greenhouse gases from surface equipment such as connectors, block valves, control valves, pressure relief valves, orifice meters, and regulators.

~~(59) "Geographic location" means the location of a well or monitoring site as referenced to a geographic coordinate system (e.g. latitude and longitude).~~

~~(60) "Geologic carbon sequestration (GCS)" means the permanent (≥ 100 years) containment of CO_2 within deep subsurface rock formations. This term does not include the capture or transport of CO_2.~~

~~(61) "Geologic formation" means a body of rock characterized by a degree of lithologic homogeneity that is prevailingly, but not necessarily, tabular and is mappable on the earth's surface or traceable in the subsurface.~~

~~[1] U.S. EPA Underground Injection Control Program, 40 C.F.R. §144 (2014).~~

~~(62) "Geomechanical analysis" means to study rock mechanical characteristics and properties, such as fault and reservoir rock stability and confining system integrity.~~

"GCS site" "storage site," or "site" means the storage complex, all injection, production, monitoring, and observation wells and plugged and abandoned wells that penetrate the storage complex, and any facilities or infrastructure inclusive of and downstream of the injection meter or wellhead of the injection well (whichever is further upstream from injection) and any other location that is identified as requiring in-situ monitoring to ensure permanent storage of injected CO_2.

~~(63)~~ "Greenhouse gas emissions reductions" or "GHG emissions reductions" means the net amount of greenhouse gas emissions (MT CO_2e) reduced through CCS projects under the LCFS.~~CO_2) avoided by limiting the carbon intensity of fuels under LCFS.~~

~~(64) "Governing equation" means the mathematical formulae that form the basis of a computational code. For computational modeling, they govern the predicted behavior of fluids in the subsurface provided by the code. Governing equations are mathematical approximations for describing flow and transport of fluids and their components in the environment.~~

~~(65) "Hydraulic conductivity" is a measure of a material's capacity to transmit a fluid. It is defined as a constant of proportionality relating the specific medium under a unit hydraulic gradient.~~

~~(66) "Hydraulic head" is the force per unit area exerted by a column of liquid at a height above a depth and pressure of interest. If connected by permeable flow paths, fluids flow down a hydraulic gradient, from points of higher hydraulic head to points of lower hydraulic head.~~

~~(67) "Injectivity" means the pressure differential over existing reservoir pressure required to inject a unit volume of fluid in a given unit of time. It is typically expressed as psi/bbl/day (psi per barrel per day), but can be expressed in any combination of pressure, volume, and time units.~~

~~(68) "Isopach map" means a contour map showing equal values of true stratigraphic thickness of a formation.~~

~~(69) "Leak-off test" is a test to determine the strength or fracture pressure of the formation, usually conducted immediately after drilling below a new casing shoe.~~

~~(70) "Liner" means a casing string that does not extend to the top of the wellbore (i.e., the ground surface), but instead is anchored or suspended from inside the bottom of the previous casing string.~~

~~(71) "Lithofacies" means a mappable subdivision of a rock unit with distinctive and characteristic lithologic features.~~

~~(72) "Lithology" means the general description and classification of a rock or rock sequence in terms of their color, texture, and composition.~~

~~(73) "Lithostatic stress" means component of confining pressure derived from the weight of the column of rock and fluid above a specified level.~~

~~(74) "Mechanical integrity" means that all well barrier envelopes, including but not limited to, the tubing, packer, wellhead, and casing, reliably perform their primary functions of containing pressure and are free from leakage.~~

~~(75) "Mechanical integrity test" means a test that consists of two parts conducted on a well to ensure that there are no leaks and that the mechanical components of the well function in a way that is protective of public health and the environment. The injection well has two parts: internal and external. The internal part has mechanical integrity if no leakage is noted in the packer, casing, or tubing. The external part has mechanical integrity if no movement of fluid is noted the vertical channels that are adjacent to the well.~~

~~(76) "Microannuli" means small gaps that may form between the casing or liner and the surrounding cement sheath within a well.~~

~~(77) "Model domain" means the lateral extent of the model in all directions.~~

~~(78) "Model parameter" means a variable in the governing equations of a computational model that may vary throughout the domain, or may vary in space and time. Various system aspects are sometimes lumped together in simulation models and described by effective parameters that are estimated or averaged. Parameters describe properties of the fluids present, porous media, and fluid sources and sinks (e.g., injection well). Examples of model parameters include intrinsic permeability, fluid viscosity, and fluid injection rate.~~

~~(79) "Multiphase flow" means the flow of two immiscible phases. For the purposes of the CCS Protocol, the pertinent phases are CO_2 (as a gas, liquid, or supercritical fluid), and brine or oil.~~

~~(80) "Net worth" means total assets minus total liabilities and is equivalent to owner's equity.~~

~~(81) "Net working capital" means current assets minus current liabilities.~~

"Low Carbon Fuel Standard Regulation" or "LCFS Regulation" or "LCFS" means title 17, California Code of Regulations (CCR) sections 95480-95503.

~~(82)~~ "Permanent ~~sequestration~~Storage" or "~~p~~Permanence" means sequestered CO_2 will remain within the storage complex for at least 100 years post-injection completion, as demonstrated by permanence certification under the GCS Protocol.

~~(83) "Permeability" means the measure of a rock's ability to transmit fluids.~~

~~(84) "Petrophysical analysis" means the study of the fundamental chemical and physical properties of reservoir rocks and their contained fluids. The term, "petrophysics," encompasses multiple types of rock studies, including core analysis, sample descriptions, petrography, scanning electron microscopy, well log analysis, and other forms of detailed laboratory data.~~

~~(85) "Plume stabilization" means that CO_2 plume migration and pressure changes are small and predictable, such that the measured rate of plume migration has a high certainty of no CO_2 leakage over a 100-year period.~~

~~(86) "Pore pressure" means the pressure of a fluid held within spaces between particles (i.e. pore space) in a rock.~~

~~(87) "Pore space" means the voids in a rock or soil that can be filled by a fluid, such as water, air, or CO_2.~~

~~(88) "Porosity" means the volume percentage of pore space.~~

~~(89) "Post-injection site care" means appropriate monitoring and other actions (including corrective action) needed following the completion of injection to ensure permanence of sequestered CO_2.~~

~~(90) "Post-injection site care and monitoring period" means the time between the date of injection completion and 100 years after injection completion.~~

~~(91) "Precipitation kinetics" means the rates of mineral precipitation from a solution. Mineralization reactions are very sensitive to kinetic rate parameters.~~

~~(92) "Pressure fall-off test" means a field test conducted by ceasing injection for a period (i.e., shutting-in the well) and monitoring pressure decay at the well. The pressure change is analyzed using pressure transient analysis, a technique based on the mathematical relationships between flow rate, pressure, and time. The information from these analyses helps determine~~

~~injection potential. It can also derive permeability, reservoir boundary shape, and reservoir pressures.~~

~~(93) "Project GHG emissions" means the GHG emissions from various activities associated with a CCS project.~~

~~(94) "Pump test" means a field experiment in which a well is pumped at a controlled rate and water-level response (drawdown) is measured in one or more surrounding observation wells and optionally in the pumped well itself. Response data from pumping tests are used to estimate the hydraulic properties of aquifers, evaluate well performance, and identify aquifer boundaries.~~

~~(95) "Reactive transport model" means a model of the chemical reactions between constituents (e.g., injected CO_2, formation fluids, and the reservoir rock). These models incorporate rate-limited intra-aqueous reactions, mineral dissolution and precipitation, changes in porosity and permeability due to these reactions, and multi-component gas mixtures to model and predict the impact of CO_2 and its co-injectates (e.g., hydrogen sulfide, sulfur dioxide) on aquifer acidification, the concomitant mobilization of metals, and any mineral trapping of CO_2. These models can also be used to assess corrosion of well construction materi~~

~~(96)~~ "Recycled CO_2" means CO_2 that is separated from oil, water, and natural gases, and reinjected back into the reservoir.

~~(97) "Relative permeability" means the ratio of the effective permeability of a particular fluid at a particular saturation to the absolute permeability of that fluid at total saturation (dimensionless). If a single fluid is present in a rock, its relative permeability is 1.0.~~

~~(98) "Rock compressibility" means the relative volume change of matter per unit pressure change under conditions of constant temperature. Rock compressibilities are typically displayed in psi^{-1}.~~

~~(99) "Sequestration and storage site" means the surface site and corresponding infrastructure where CO_2 injection occurs, and includes the storage complex at depth, where CO_2 is stored.~~

~~(100) "Site closure" means the point or date, after at least 100 years and as determined by the Executive Officer following the requirements under subsection C.5.2, at which point the CCS Project Operator is released from post-injection site care responsibilities.~~

~~(101) "Sequestration zone" means the reservoir into which CO_2 is injected for geologic sequestration.~~

~~(102) "Skin factor" means a dimensionless pressure drop caused by a flow restriction in the near-wellbore region, typically associated with damage during drilling and well operations.~~

~~(103) "Specific storage" means the volume of water released from storage from a unit volume of aquifer per unit decline in hydraulic head (displayed in L^{-1}).~~

~~(104) "Step rate test" means test in which a fluid is injected for a defined period in a series of increasing pump rates. The resulting data are used to determine the maximum safe injection rate possible without fracturing the reservoir rock.~~

~~(105) "Stratigraphic test well" means a hole drilled for the sole purpose of gaining structural or stratigraphic information to aid in subsurface exploration.~~

~~(106) "Storage coefficient" means the volume of water released from storage by a confined aquifer per unit surface area of aquifer per unit decline in hydraulic head normal to the surface and equal to the product of specific storage and the saturated thickness (dimensionless).~~

~~(107)~~ "Storage complex" means the three-dimensional subsurface volume ~~that is characterized, modified by corrective actions, and monitored so that the CCS Project is able to meet the requirements for carbon sequestration under the Permanence Requirements (section C).~~

~~(A) For saline and depleted oil and gas reservoirs, the storage complex includes the injection zone (in which the CO_2 is emplaced), a sequestration volume, which is expected to contain the CO_2, and overlying and possibly underlying geologic~~comprised of a storage zone used for the injection and permanent storage of CO_2, the primary confining layer, and may include other formations that ~~are required to provide assurance of storage. The storage complex must include a multilayered confining system that retards vertical~~ dissipate pressure or impede CO_2 plume migration vertically or laterally. Definitions, characteristics, and the required testing and monitoring plan requirements for each type of storage complex are described in the GCS Protocol. ~~of CO_2. The storage complex must extend laterally over (1) the volume from which CO_2 (as a free or dissolved phase) could escape from storage in the subsurface if a permeable pathway exists, and (2) the area over which the plume may migrate.~~

~~(B) For CCS projects utilizing CO_2 injection for EOR purposes, the storage complex is the three-dimensional extent of the reservoir used for oil production and CO_2 storage. The storage complex for a CO_2-EOR CCS project is delineated by the geologic extent of the reservoir as defined by impervious rock, structural closure, decrease or loss of porosity and~~

~~permeability, or natural hydrodynamic forces in a three dimensional volume.~~

~~(108) "Stratigraphy" means the classification of sedimentary rocks based on their lithologic properties and geometric relations, such as spatial distribution, depositional environment, composition, and age.~~

~~(109) "Supercritical CO_2" means the physical state where CO_2 exhibits properties of both a gas and a liquid when its temperature and pressure exceeds the critical temperature (87.98 °F) and pressure (1,071 psi).~~

~~(110) "System boundary" means a delineation of activities/processes that are considered part of the project when analyzing emissions from CCS projects.~~

~~(111) "Tangible net worth" means the tangible assets that remain after deducting liabilities; such assets would not include intangibles such as goodwill and rights to patents or royalties.~~

~~(112) "Total dissolved solids (TDS)" means milligrams per liter of total dissolved solids content. Solids content includes inorganic salts (principally calcium, magnesium, potassium, sodium, bicarbonates, chlorides, and sulfates) and some small amounts of organic matter that are dissolved in water.~~

~~(113) "Transmissibility" means a measure of the conductivity of the formation corrected for the viscosity of the flowing fluid. It is a coefficient associated with Darcy's law, which characterizes flow through porous media. It is equal to the coefficient of permeability (hydraulic conductivity) multiplied by the thickness of the formation.~~

~~(114) "Transmissive fault or fracture" means a fault or fracture that has sufficient permeability and vertical extent to allow fluids to move laterally or vertically along the fault or fracture, or within an associated damaged zone.~~

~~(115) "True stratigraphic thickness" means the thickness of rock layer after correcting for the dip (inclination) of the layer and the deviation of the well that penetrates it. Values of true stratigraphic thickness in an area can be plotted to create an isopach map.~~

~~(116) "True vertical depth" means the vertical distance from a point in the well (usually the current or final depth) to a point at the surface. If the well is deviated, the measurement may be different from the "measured depth."~~

~~(117) "True vertical thickness" means the thickness of a layer of rock measured vertically from a reference point at the surface. Values of true vertical thickness in an area can be plotted to create an isopach map.~~

~~(118) "Tubing" or "production tubing" means any tubing used to inject or produce fluids, respectively.~~

~~(119) "Unconfined compressive stress" is a measure of a material's strength. The unconfined compressive strength (UCS) is the maximum axial compressive stress that a right-cylindrical sample of material can withstand under unconfined conditions. It is also known as the "uniaxial compressive strength" of a material because the application of compressive stress is only along one axis-the longitudinal axis-of the sample.~~

~~(120) "Vadose zone" means the unsaturated zone of the subsurface above the groundwater table. The soil and rock within this zone typically contains air and water within its pore space.~~

~~(121) "Validation" means, for purposes of this protocol, an initial review by a third party that is approved by the Executive Officer of modeling, plans, and data submitted as part of the application for permanence, against the requirements in this protocol. Any validation services conducted under the protocol are separate from verification services.~~

"Subsurface CO_2 leakage" means the vertical movement of stored CO_2 out of the storage complex that does not reach the atmosphere.

~~(122)~~ "Vented emissions" means intentional or designed releases of CH_4 or CO_2 including process designed flow to the atmosphere through seals or vent pipes, equipment blowdown for maintenance, and direct venting of gas used to power equipment (such as pneumatic devices).

~~(123) "Verification" means a systematic, independent, and documented process for the evaluation of reported data against the requirements specified in this protocol. Verification occurs after a CCS Project Operator submits quarterly or annual reports of GHG emissions reductions.~~

~~(124) "Vertical stress" means the force per unit area imposed on a layer of rock. Vertical stress is the combined stress due to the total weight of rock and interstitial fluids above a specified depth.~~

~~(125) "Viscosity" means the measure of a liquid's resistance to flow.~~

~~(126) "Well" or "wellbore" means a hole that is drilled into the Earth's subsurface. A wellbore can be encased by materials such as steel and cement, or it may be uncased.~~

~~(127) "Wireline" means a wire or cable that is used to deploy tools and instruments downhole and transmits data to the surface.~~

~~(128) "Workover" means the process of performing major maintenance or remedial treatments on an injection or production well. In many cases, workover implies the removal and replacement of the production tubing string after the well has been killed and a workover rig has been placed on location.~~

For any term not defined in subchapter 1.2(a) of this Methodology, the definitions in section 95481 of the LCFS Regulation, and the definitions in sections 39010 through 39060 of the Health and Safety Code, except when included in the LCFS Regulation, shall apply.

(b) Acronyms:

~~"API" means American Petroleum Institute.~~
~~"APCD" means Air Pollution Control District.~~
~~"AQMD" means Air Quality Management District.~~
~~"ASTM" means ASTM International, formerly known as the American Society for Testing and Materials.~~
~~"CARB" means California Air Resources Board.~~
"CA-GREET" means the California - Greenhouse gases, Regulated Emissions, and Energy use in Transportation Model~~, as referred to~~ (version specified in the LCFS ~~r~~Regulation).
~~"CERCLA" means Comprehensive Environmental Response, Compensation, and Liability Act.~~
~~"CAA" means Clean Air Act.~~
~~"CWA" means Clean Water Act~~
"CCS" means Carbon Capture and Sequestration.
"CH_4" means methane.
~~"CIL" means casing inspection log.~~
"CO" means carbon monoxide.
"CO_2" means carbon dioxide.
"CO_2e" means CO_2 equivalent.
~~"$CO_{2(aq)}$" means carbon dioxide dissolved in an aqueous solution.~~
~~"$CO_{2(g)}$" means carbon dioxide as a free gas phase.~~
"CO_2-EOR" means CO_2-enhanced oil recovery.
"GCS" means geologic carbon ~~sequestration~~storage.
~~"DOGGR" means the California Division of Oil, Gas, and Geothermal Resources.~~
"GHG" means greenhouse gas.
~~"GPS" means global positioning system.~~
"LCFS" means the Low Carbon Fuel Standard (title 17, California Code of Regulations~~, section~~ (CCR), sections 95480~~-et seq.)~~-95503.)
"MRR" means the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (title 17, California Code of Regulations, sections 95100 et seq.)
"MT" means metric ton.
"N_2O" means nitrous oxide.
~~"NESHAPS" means the National Emission Standards for Hazardous Pollutants preconstruction approval under the Clean Air Act.~~

~~"NPDES" means the National Pollution Discharge Elimination System under the Clean Water Act.~~
~~"PSD" means the Prevention of Significant Deterioration program under the Clean Air Act.~~
~~"PSI" means pounds per square inch.~~
~~"RCRA" means the Resource Conservation and Recovery Act.~~
~~"SDWA" means Safe Drinking Water Act.~~
~~"SIC" means Standard Industrial Classification codes for classifying industries by a four-digit code.~~
"SSR" means sources, sinks, and reservoirs.
~~"TDS" means total dissolved solids.~~
~~"TOC" means total organic carbon.~~
~~"US EPA UIC" or "UIC" means the United States Environmental Protection Agency Underground Injection Control program.~~[2]
"VOC" means volatile organic compound.

~~[2] EPA Underground Injection Control Program, 40 C.F.R. §144, §145, and §146 (2014).~~

~~**B. ACCOUNTING REQUIREMENTS FOR CCS PROJECTS UNDER THE LCFS**~~

~~**1. System Boundary**~~

~~The Accounting~~**Chapter 2. GHG Quantification Requirements for CCS** ~~delineate a system boundary that covers all CO_2~~**Projects**

This Methodology establishes the requirements for quantifying GHG emissions, GHG emissions reductions, and net CO_2 sequestration associated with CCS projects seeking LCFS crediting. CCS Project Operators must comply with the GHG quantification requirements pursuant to Chapters 2 and 3 in calculating GHG reductions to quantify emissions and emission reductions consistent with this Methodology, the LCFS Regulation, and all applicable requirements in the GCS Protocol.

2.1. GHG Quantification Requirements

(a) All GHG emissions sources, sinks, and reservoirs (SSRs) ~~from a CCS project. All SSRs~~ that fall within the ~~system~~CCS project boundary must be identified and quantified. CCS Project Operators must use metered data where required, apply the equations in this Methodology, and maintain documentation demonstrating the accuracy, completeness, and reproducibility of all calculations.

(b) For each reporting period, CCS Project Operators must quantify:
- (1) Gross captured CO_2;
- (2) CO_2 delivered for injection;
- (3) CO_2 injected;
- (4) CO_2 permanently stored, consistent with the GCS Protocol;
- (5) Direct and indirect GHG emissions associated with capture, conditioning, transport, injection, monitoring, and verification;
- (6) Any subsurface or atmospheric leakage; and
- (7) Net GHG reductions for LCFS crediting.

(c) GHG quantification must reflect the actual operating conditions at the capture facility, during transportation, and at the GCS site, and must be consistent with LCFS fuel pathway and project-based reporting requirements. Greenhouse gas emission factors and global warming potentials CA-GREET must be used. All references to CA-GREET in this Methodology refer to the version specified by the LCFS Regulation.

(d) All parameters required by this Methodology must be monitored, verified, and available for audit pursuant to the LCFS Regulation and the GCS Protocol.

2.2. Project Boundary

(a) The quantification requirements for CCS are delineated by a project boundary that covers all SSRs from a CCS project. All SSRs within the project boundary

must be accounted for when quantifying GHG emissions reductions from CO_2 sequestration.

(b) The CCS project boundary encompasses all activities required to capture, condition, transport, inject, and permanently sequester CO_2 in accordance with the GCS Protocol. The project boundary includes both direct and indirect GHG emissions.

(c) At a minimum, the following SSRs must be included:

(1) Capture System (including dehydration and compressions) SSRs:

(A) Energy use for CO_2 capture (steam, electricity, fuel combustion); and

(B) Chemical and fuel production and consumption.

(2) CO_2 Transport SSRs:

(A) Energy used for pipeline transport, if applicable;

(B) Energy used for trucks, rail, or ships transport, if applicable;

(C) Fuel production; and

(D) Land use change for new pipelines.

(3) Injection and Storage SSRs:

(A) Energy use for injection and sequestration;

(B) Fuel production;

(C) Venting events and fugitive emissions;

(D) Pressure management;

(E) Subsurface distribution of injected CO_2;

(F) Dissolution, residual trapping, and mineralization;

(G) Any CO_2 leakage, whether atmospheric or subsurface; and

(H) Land use change for new storage complexes.

(d) Emissions associated with fuel, electricity, steam, chemicals, and other inputs must be calculated using CA-GREET emission factors. If an emission factor for a particular fuel is not available in CA-GREET or in Appendix E, applicants must apply to CARB for approval to use an emission factor from an alternative source.

(e) The specific types of equipment and sources ~~covered by~~included within the ~~system~~project boundary ~~can~~may vary ~~by~~depending on the CCS project type~~s~~. Figure 1 ~~shows~~illustrates the ~~system~~project boundary for ~~capturing~~projects in which captured CO_2 ~~and sequestering it~~is sequestered in oil and gas reservoirs used for CO_2-EOR ~~indicating which~~, including the associated SSRs ~~are included.~~ . Figure 2 ~~shows~~illustrates the ~~system~~project boundary for capturing CO_2 and sequestering it in depleted oil and gas reservoirs and saline formations.

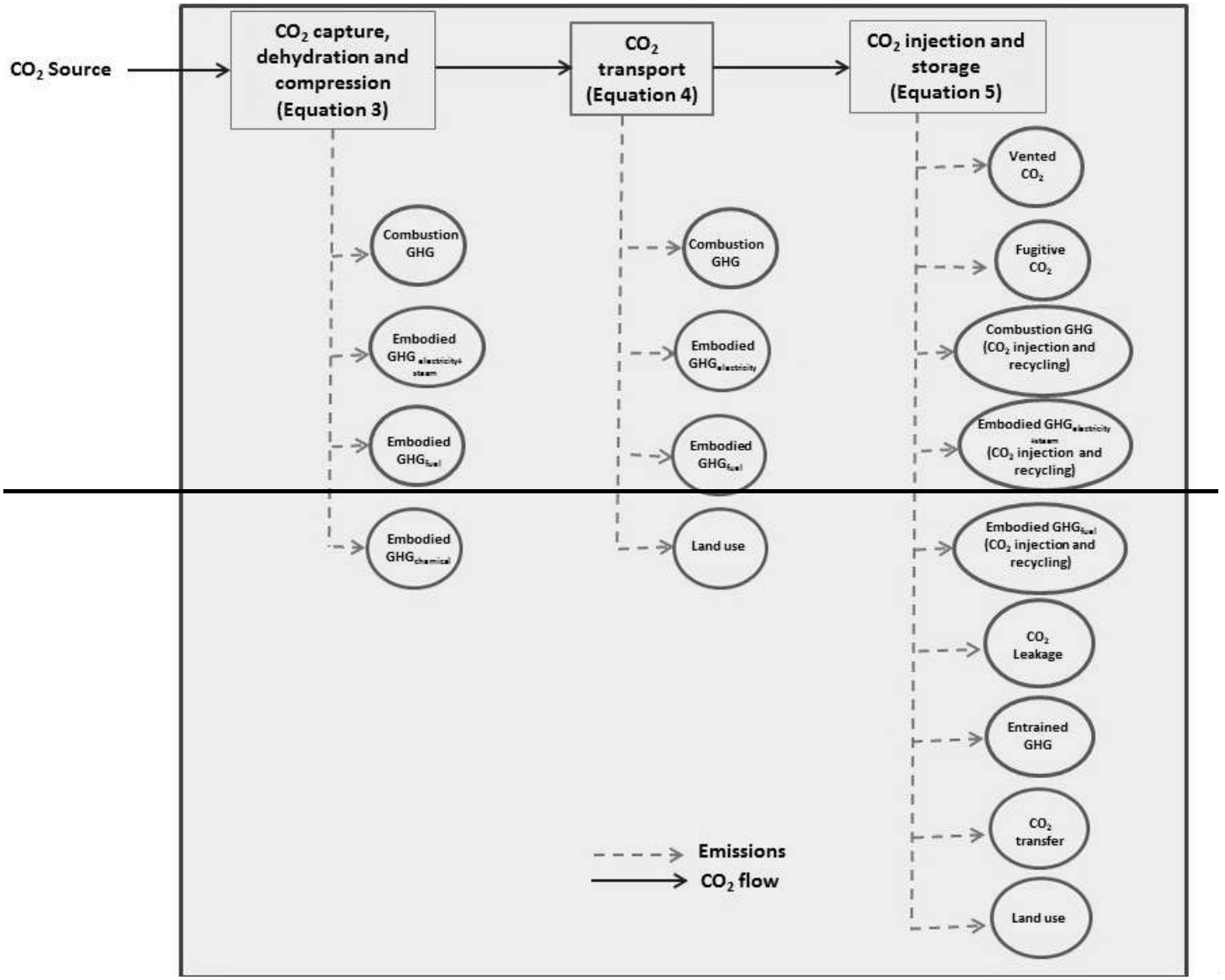
~~In either case, the system boundary begins with carbon capture and ends with injection operations including CO_2 leakage.~~ Any emissions downstream of the ~~sequestration~~GCS site are excluded from the project boundary (except entrained CO_2 in

the case of CO_2-EOR~~) are excluded since they~~), as such emissions are associated with ~~the~~ downstream products rather than ~~the~~ CCS project~~.~~

(f) operations.

(g) CO_2 that is permanently stored in accordance with the GCS Protocol is considered sequestered. CO_2 that migrates outside the storage complex or is released to the atmosphere must be quantified as leakage.

(h) Emission sources outside the defined CCS project boundary may not be included in LCFS crediting calculations unless explicitly allowed in this Methodology.


CO_2 Source
CO_2 capture, dehydration and compression (Equation 3)
CO_2 transport (Equation 4)
CO_2 injection and storage (Equation 5)
Combustion GHG
Embodied $GHG_{electricity+steam}$
Embodied GHG_{fuel}
Embodied $GHG_{chemical}$
Combustion GHG
Embodied $GHG_{electricity}$
Embodied GHG_{fuel}
Land use
Vented CO_2
Fugitive CO_2
Combustion GHG (CO_2 injection and recycling)
Embodied $GHG_{electricity+steam}$ (CO_2 injection and recycling)
Embodied GHG_{fuel} (CO_2 injection and recycling)
CO_2 Leakage
Entrained GHG
CO_2 transfer
Land use
Emissions
CO_2 flow

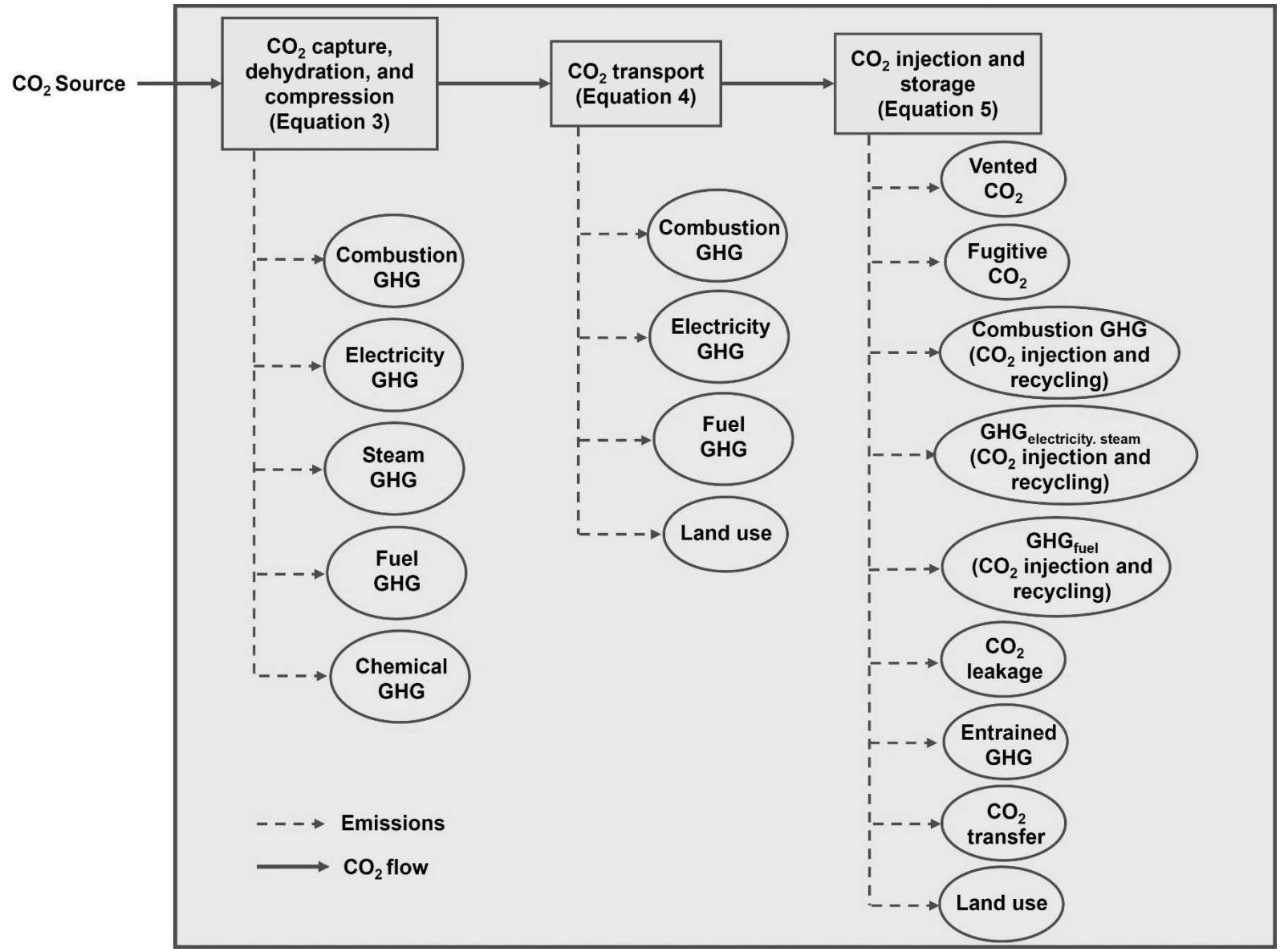


Figure 1. ~~System~~Project boundary for CO_2 capture and sequestration in oil and gas reservoirs used for CO_2-EOR.

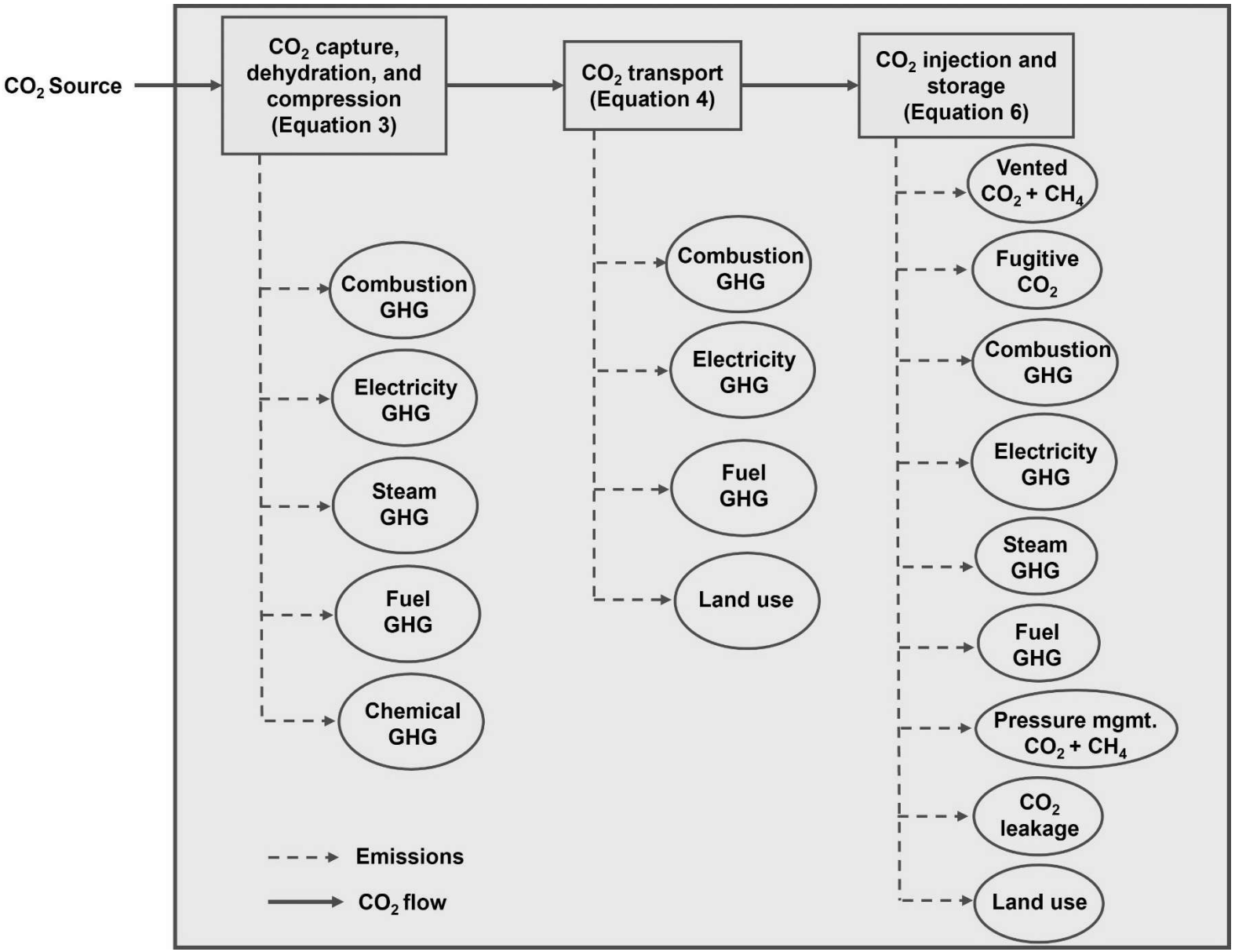


Figure 2. Project boundary for CO_2 capture and sequestration in depleted oil and gas reservoirs and saline formations.

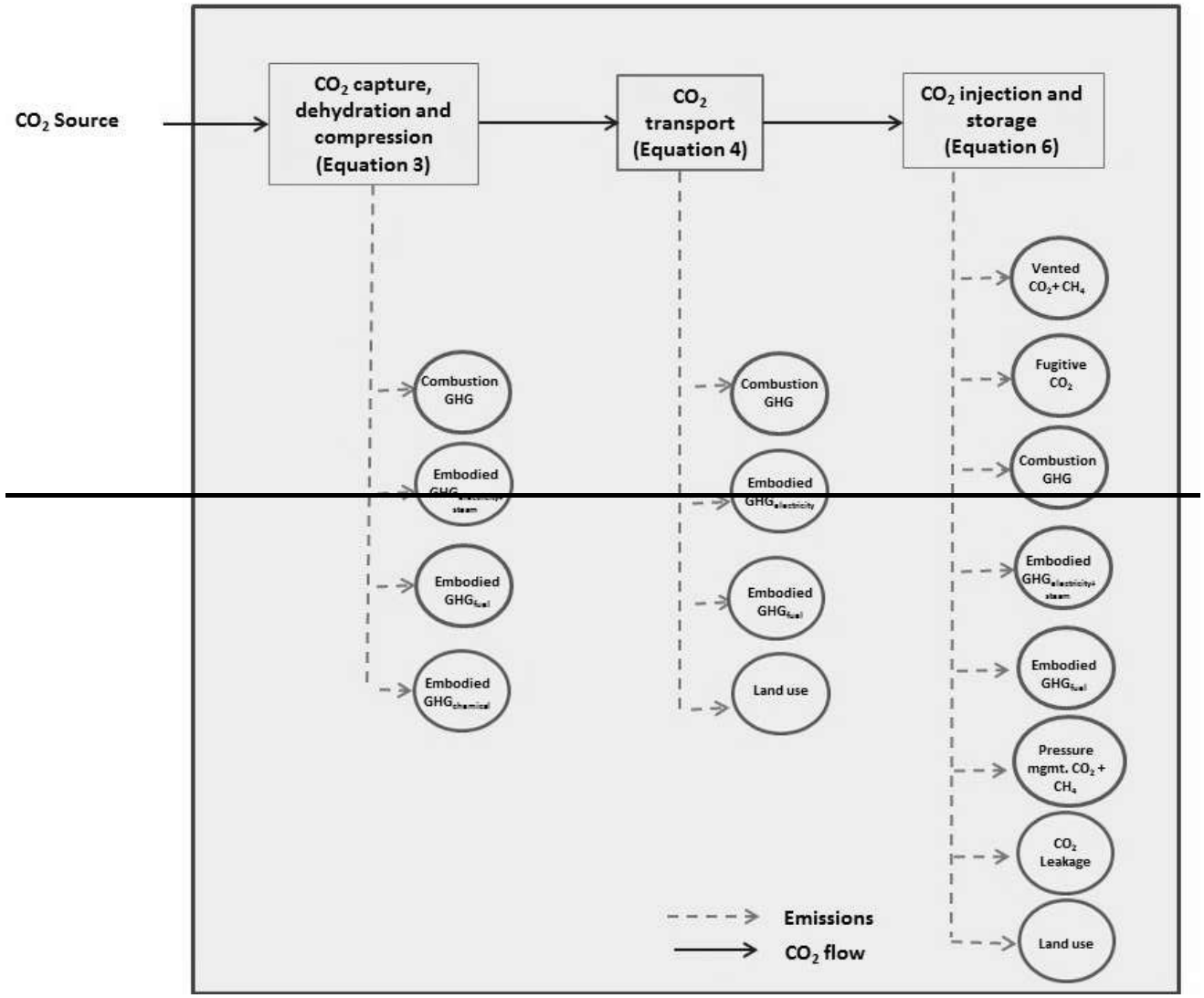


Figure 2. System boundary for CO_2 capture and sequestration in depleted oil and gas reservoirs and saline formations.

~~2.~~ Chapter 3. Quantification of ~~Geologic Sequestration CO_2~~ CCS Project GHG Emission Reductions

This ~~section~~chapter describes the methodology for estimating GHG emissions reductions by sequestering CO_2 in depleted oil and gas or saline reservoirs and through EOR.

~~2.1.~~3.1. Covered Greenhouse Gas Emissions for ~~the LCFS~~GHG accounting

(a) In addition to CO_2, CH_4, and N_2O, CA-GREET~~, the model used in LCFS~~ accounting~~,~~ treats ~~volatile organic compounds (VOC) and carbon monoxide (~~VOCs and CO~~)~~ as GHGs because they are eventually oxidized to CO_2.

(b) In the context of CCS projects, emissions covered in this document under the LCFS are CO_2, N_2O, CH_4, CO and VOC.

(c) The global warming potential values listed in ~~the~~ CA-GREET model are used to determine the CO_2 equivalent of emissions.

(d) If N_2O, CH_4, CO and VOC present in the CO_2 stream are sequestered during CO_2 injection, they are not included in the quantification and will not be credited under LCFS.

~~2.2.~~3.2. Greenhouse Gas Emissions ~~Reductions~~ Calculation

~~Net annual~~**Note:** CCS Project Operators are required to submit either quarterly or annual project reports. The units in Equations 1 through 6 are expressed as either MT CO_2e per year or MT CO_2e per quarter, depending on the reporting frequency selected by the project for verification and transaction.

(a) Net GHG emissions reductions from CCS projects must be quantified using Equation 1.

$$\sim\sim GHG_{reduction} = CO_{2_{injected}} \sim\sim GHG_{net\ reduction} = CO_{2_{injected}} - GHG_{project} \quad (1)$$

Where:

~~$GHG_{reduction}$ = Net GHG reductions (MT CO_2e/year).~~
~~$CO_{2_{injected}}$ = Amount of injected CO_2 (MT CO_2/year). Excludes recycled CO_2 in the case of CO_2 EOR (equal to purchased CO_2 per year measured before the point of injection and after transportation[3]).~~
~~$GHG_{project}$ = CCS project GHG emissions (MT CO_2e/year).~~

~~[3] See subsection C.4.1(a)(14)(F)3 for requirements related to the measurement and quantification of flow meter data.~~

$GHG_{net\ reduction}$	=	Net GHG reductions.
$CO_{2\ injected}$	=	Amount of injected CO_2. Excludes recycled CO_2 in the case of CO_2-EOR (equal to purchased CO_2 measured before the point of injection and after transportation).
$GHG_{project}$	=	CCS project GHG emissions.

(b) If the injected CO_2 consists of CO_2 derived from various sources/facilities, a mass-balance approach must be used to assign the injected amount to the various sources of carbon capture based on metered data and contractual agreements between the CO_2 supplier and ~~CCS project~~GCS operator. ~~-~~CO_2 from natural underground CO_2 reservoirs must be omitted from $CO_{2injected}$ ~~in Equation .~~.

~~(b)~~(c) ~~Annual~~ CCS project GHG emissions must be calculated using Equation 2. ~~-~~Each variable in ~~Equation~~ the equation must include both direct emissions as well as upstream (indirect) emissions associated with the corresponding specific activity~~,~~ and must be determined pursuant to ~~subsections B~~subchapters 3.2~~.~~(c) through ~~B~~3.2~~.2~~(e(v) below.

$$GHG_{project} = GHG_{capture} + GHG_{transport} + GHG_{injection} + GHG_{dLUC} \quad (2)$$

Where:

~~$GHG_{project}$ = CCS project GHG emissions (MT CO_2e/year).~~
~~$GHG_{capture}$ = GHG emissions associated with carbon capture, dehydration, and compression (MT CO_2e/year).~~
~~$GHG_{transport}$ = GHG from CO_2 transport (MT CO_2e/year). Transport can be by pipeline, ships, rail, or trucks.~~
~~$GHG_{injection}$ = GHG emissions from injection operations (MT CO_2e/year).~~
~~GHG_{dLUC} = GHG emissions from direct land use change (MT CO_2e/year).~~

~~Annual~~

$GHG_{project}$	=	CCS project GHG emissions.
$GHG_{capture}$	=	GHG emissions associated with carbon capture, dehydration, and compression.

$GHG_{transport}$	=	GHG from CO_2 transport. Transport can be by pipeline, ships, rail, or trucks
$GHG_{injection}$	=	GHG emissions from injection operations.
GHG_{dLUC}	=	GHG emissions from direct land use change for transport and injection.

(d) Installation of new pipelines and construction of new CO_2 injection sites can cause changes in above and belowground carbon stock depending on the type of land use where these facilities are going to be located. In such a case, direct land use change GHG emissions must be calculated using land use change emission factors utilized in the Global Trade Assessment Project model or using similar CARB-approved land use change emission factors. Direct land use change emissions must be amortized over a period of 30 years. If CCS projects utilize existing pipeline and CO_2 injection infrastructure where land use change has already occurred, direct land use change emissions are considered part of the baseline and are not considered. Indirect land use change GHG emissions are omitted from the quantification requirements since they are considered negligible.

~~(c)~~(e) GHG emissions from carbon capture, dehydration, and compression must be calculated according to Equation 3. ~~-~~GHG emissions from fuel combustion and electricity use must be determined by using emission factors available in CA-GREET. If an emission factor for a particular fuel is not available in CA-GREET or in Appendix E, applicants must ~~refer~~apply to ~~Tables E1-E3 in Appendix E.~~[4]CARB for approval to use an emission factor form an alternative source.

$$GHG_{capture} = GHG_{combustion} + \sout{EmbodiedGHG_{electricity+steam}} + \sout{EmbodiedGHG_{fuel}} GHG_{fuel} + \sout{EmbodiedGHG_{chemical}} GHG_{chemical} \quad (3)$$

Where:

~~$GHG_{capture}$ = GHG emissions from capture, dehydration, and compression (MT CO_2e /year).~~

~~$GHG_{combustion}$ = GHG emissions from fuel combustion in stationary equipment including emissions from parasitic load (MT CO_2e/year).~~

~~$EmbodiedGHG_{electricity+steam}$ = Embodied (upstream) GHG emissions from purchased electricity and steam use (MT/CO_2e year).~~

~~[4] Combustion emission factors provided in the CA-GREET and Table A1 may differ from the emission factors mentioned in the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (CARB).~~

~~$EmbodiedGHG_{fuel}$~~

~~= Embodied (upstream) GHG emissions of fuel used in stationary equipment including embodied emissions associated with parasitic load (MT/CO_2e year).~~

~~$EmbodiedGHG_{chemical}$~~

~~= Embodied (upstream) GHG emissions from chemicals used in carbon capture, including replacements from loss/deterioration (MT CO_2e/year). Depending on the technology used, carbon capture may involve the use of chemicals such as monoethanolamine (MEA), NaOH, and activated carbon.~~

$GHG_{capture}$ = GHG emissions from capture, dehydration, and compression.

$GHG_{combustion}$ = GHG emissions from fuel combustion in stationary equipment including emissions from parasitic load.

$GHG_{electricity+steam}$ = GHG emissions from purchased electricity and steam.

GHG_{fuel} = GHG emissions from production and transport of fuel used in stationary equipment including emissions associated with parasitic load.

$GHG_{chemical}$ = GHG emissions from production and transport of chemicals used in carbon capture, including replacements from loss/deterioration.

Depending on the technology used, carbon capture may involve the use of chemicals such as monoethanolamine (MEA), NaOH, and activated carbon.

GHG emissions from fuel combustion ($GHG_{combustion}$) must be calculated using the ~~amounts~~volume of fuels used, and their corresponding emission factors provided in ~~the~~ CA-GREET ~~model.~~. If specific emission factors are not available in CA-GREET, ~~refer~~applicants must submit a request to ~~emission factors provided in Tables E1-E3.~~

(f) ~~Embodied GHG~~ CARB for approval of emissions ~~of~~factors.

(g) GHG emissions from electricity must be calculated using electricity emission factors in ~~the~~ CA-GREET ~~model. Embodied~~. GHG emissions ~~of~~from steam ~~can~~must be calculated based on the enthalpy of steam ~~as well as~~, the fuel source and type, the emission factor of the fuel used, and the efficiency of the boiler or the cogeneration system.

(h) ~~Embodied~~ GHG emissions of chemicals (~~*Embodied*~~$GHG_{chemical}$) must be calculated using ~~the~~ CA-GREET ~~model or~~or must submit a request to CARB to use an equivalent method if the chemical in question is not modelled in CA-GREET.

(i) ~~Embodied (upstream)~~ GHG emissions of fuel (~~*Embodied*~~GHG_{fuel}) must be calculated using the CA-GREET model or an equivalent method if the fuel in question is not modelled in CA-GREET.

~~(d)~~(j) ~~Annual~~ GHG emissions from CO_2 transport must be calculated using Equation 4.

$$GHG_{transport} = GHG_{combustion} + \sim\sim EmbodiedGHG_{electricity}\sim\sim GHG_{electricity} + \sim\sim EmbodiedGHG_{fuel}\sim\sim GHG_{fuel} \quad (4)$$

Where:

~~$GHG_{transport}$ = GHG emissions from CO_2 transport (MT CO_2e/year).~~

~~$GHG_{combustion}$ = GHG emissions from fuel combustion at stationary equipment (MT CO_2e/year) used in CO_2 transport.~~

~~$EmbodiedGHG_{electricity}$ = Embodied (upstream) GHG emissions from electricity use (MT CO_2e/year) in CO_2 transport.~~

~~$EmbodiedGHG_{fuel}$ = Embodied (upstream) GHG emissions of fuels used in CO_2 transport (MT CO_2e/year).~~

$GHG_{transport}$ = GHG emissions from CO_2 transport.

$GHG_{combustion}$ = GHG emissions from fuel combustion at stationary equipment used in CO_2 transport.

$GHG_{electricity}$ = GHG emissions from electricity use in CO_2 transport.

GHG_{fuel} = GHG emissions from production and transport of fuels used in CO_2 transport.

(k) If a pipeline carries CO_2 to multiple geological sites or serves multiple uses, CO_2 transport emissions must be prorated using the mass-based allocation method and assigned to the CCS project under consideration.

(l) If the injected CO_2 comes via two or more different transport modes, ~~-~~$GHG_{transport}$ ~~in Equation~~ must be calculated and summed together for each transport mode.

~~(e)~~(m) ~~Annual~~ GHG emissions from CO_2 injection operations must be calculated using Equation 5 for CO_2-EOR and Equation 6 for depleted oil and gas reservoirs and saline formations.

~~Entrained CO_2~~ GHG emissions ~~in Equation are calculated using the formula provided in Equation F.1 in Appendix F.~~

(n) ~~GHG Emissions~~ from fuel combustion, electricity use, and ~~embodied (upstream)~~ emissions from production of fuels ~~must be restricted~~are only from operations related to CO_2 injection and recycling operations only~~.~~ (within the project boundary). GHG emissions associated with fuel combustion, electricity use and ~~embodied (upstream)~~ emissions of fuels used for other activities at the ~~CO_2-EOR~~injection site (outside the project boundary) are excluded ~~from the credit calculation~~ because ~~they~~the emissions are assigned to the ~~crude oil production pathway~~other activities.

$$GHG_{injection} = GHG_{combustion} + \sout{EmbodiedGHG_{electricity+steam}} GHG_{electricity+steam} + \sout{EmbodiedGHG_{fuel}} GHG_{fuel} + CO_{2_{vent}} + CO_{2_{fugitive}} + CO_{2_{entrained}} + CO_{2_{leakage}} + CO_{2_{transfer}} \quad (5)$$

Where:

~~$GHG_{injection}$ = GHG emissions in CO_2e associated with injection operations in CO_2-EOR (MT CO_2e/year).~~

~~$GHG_{combustion}$ = GHG emissions from fuel combustion at stationary equipment used in CO_2 injection and recycling (MT CO_2e/year).~~

~~$EmbodiedGHG_{electricity+steam}$ = Embodied (upstream) GHG emissions from electricity and steam use in CO_2 injection and recycling (MT CO_2e/year).~~

~~$EmbodiedGHG_{fuel}$ = Embodied (upstream) GHG emissions of fuels used (excluding electricity) in CO_2 injection and recycling (MT CO_2e/year).~~

~~$CO_{2_{vent}}$ = CO_2 emissions from venting (MT CO_2/year) including biogenic CO_2 and CO_2 from direct air capture.~~

~~$CO_{2_{fugitive}}$ = Fugitive CO_2 emissions from surface equipment~~

~~(MT CO_2/year) including biogenic CO_2 and CO_2 from direct air capture.~~

~~$CO_{2_{entrained}}$ = Entrained CO_2 in produced water, natural gas, and crude oil downstream of separator units (MT CO_2/year). Excludes entrained CO_2 if it is reinjected into reservoirs.~~

~~$CO_{2_{leakage}}$ = Atmospheric CO_2 leakage from the storage complex (MT CO_2/year). Includes subsurface and atmospheric leakage.~~

~~$CO_{2_{transfer}}$ = Intentional transfer of stored CO_2 outside of the CCS project boundary (MT CO_2/year).~~

$GHG_{injection}$ = GHG emissions in CO_2e associated with injection operations in CO_2-EOR.

$GHG_{combustion}$ = GHG emissions from fuel combustion at stationary equipment used in CO_2 injection and recycling.

$GHG_{electricity+steam}$ = GHG emissions from electricity and steam used in CO_2 injection and recycling.

GHG_{fuel} = GHG emissions from production and transport of fuels used (excluding electricity) in CO_2 injection and recycling.

$CO_{2\ vent}$ = CO_2 emissions from venting including biogenic CO_2 and CO_2 from direct air capture.

$CO_{2\ fugitive}$ = Fugitive CO_2 emissions from surface equipment including biogenic CO_2 and CO_2 from direct air capture.

$CO_{2\ entrained}$ = Entrained CO_2 in produced water, natural gas, and crude oil downstream of separator units. Excludes entrained CO_2 if it is reinjected into reservoirs. Entrained CO_2 emissions are calculated using the formula provided in Appendix F.

$CO_{2\ leakage}$ = Atmospheric CO_2 leakage from the storage complex. Includes subsurface and atmospheric leakage.

$CO_{2\ transfer}$ = Intentional transfer of stored CO_2 outside of the CCS project GCS site boundary.

And:

$$GHG_{injection} = GHG_{combustion} + EmbodiedGHG_{electricity+steam}GHG_{electricity+steam} + EmbodiedGHG_{fuel} + GHG_{fuel} + GHG_{vent} + GHG_{pressure} + CO_{2_{fugitive}} + CO_{2_{leakage}} \quad (6)$$

Where:

$GHG_{injection}$ = GHG emissions associated with CO_2 injection operations (MT CO_2e/year).

$GHG_{combustion}$ = GHG emissions from stationary combustion equipment (MT CO_2e/year).

$EmbodiedGHG_{electricity+steam}$ = Embodied (upstream) GHG emissions from electricity and steam use (MT CO_2e/year).

$EmbodiedGHG_{fuel}$ = Embodied (upstream) GHG emissions of fuels excluding electricity (MT CO_2e/year).

GHG_{vent} = CO_2 and CH_4 vented from equipment located between the injection flow meter and the injection wellhead (MT CO_2e/year).

$GHG_{pressure}$ = CO_2 and CH_4 emissions from pressure management activities including brine production (MT CO_2e/year).

$CO_{2_{fugitive}}$ = Fugitive CO_2 emissions from surface equipment per year (MT CO_2/year).

$CO_{2_{leakage}}$ = Atmospheric CO_2 leakage from the storage complex (MT CO_2e/year). Includes subsurface and atmospheric leakage.

$GHG_{injection}$ = GHG emissions in CO_2e associated with injection operations.

$GHG_{combustion}$ = GHG emissions from fuel combustion at stationary equipment used in CO_2 injection.

$GHG_{electricity+steam}$	=	GHG emissions from electricity and steam used in CO_2 injection.
GHG_{fuel}	=	GHG emissions from production and transport of fuels used (excluding electricity) in CO_2 injection.
GHG_{vent}	=	CO_2 and CH_4 emissions from venting.
$GHG_{pressure}$	=	CO_2 and CH_4 emissions from pressure management activities including brine production.
$CO_{2\ fugitive}$	=	Fugitive CO_2 emissions from surface equipment including biogenic CO_2 and CO_2 from direct air capture.
$CO_{2\ leakage}$	=	CO_2 leakage from the storage complex. Includes subsurface and atmospheric leakage.

(o) There are planned and unplanned venting events in CO_2 injection operations. Both must be accounted for in this Methodology. For CO_2-EOR, these must include any CO_2 taken out of the ground but not reinjected into wells towards the end of EOR project completion, and any CO_2 blowdown.

(p) Vented CO_2 emissions from CO_2-EOR must be determined for each applicable venting source using the methods described in Appendix B. In the case of CO_2 injection operations in depleted oil and gas or saline reservoirs, vented CO_2 emissions from surface facilities must be calculated using the event-based approach described in Appendix A(b~~) and Equation A.2.)~~. This must include CO_2/CH_4 releases from pressure management including brine production.

(q) In the case of CO_2-EOR operations, fugitive CO_2 emissions must be calculated using either leak detection and leaker emission factors, or using population count and emission factors as described in Appendix B. ~~-~~Fugitive CO_2 emissions occur from fittings, flanges, valves, connectors, meters, and headers associated with CO_2-EOR operations. ~~-~~In the case of CO_2 injection operations in depleted oil and gas reservoirs/saline formations, fugitive CO_2 and CH_4 emissions from equipment must be calculated using the equipment count method described in Appendix A(a~~) and Equation A.1.~~).

(r) In the case of CO_2-EOR operations, CO_2 can remain in water, natural gas and crude oil after they are separated from produced CO_2 in separators for either

sales or disposal/injection of water. ~~-~~CO_2 from these product streams will eventually be released and must be calculated using Equation F.1 in Appendix F.

(s) To be conservative, $CO_{2leakage}$ must be considered to be equal to half the detection limit of the method used to detect leaks deployed in the ~~CCS project's monitoring~~GCS site's Testing and ~~testing plan~~Monitoring Plan under the GCS Protocol, or the volume of leakage detected, whichever is ~~larger.~~ greater. The CCS Project Operator must provide a description and justification for the method used to calculate the detection limit.

(t) In cases where atmospheric or subsurface leakage has occurred, $CO_{2leakage}$ must be calculated using a method identified in the ~~CCS project's~~GCS site's Testing and Monitoring Plan under the GCS Protocol.

(u) In the event the stored CO_2 is intentionally released via decompression and transferred to other EOR locations it must be counted as emissions and included in $CO_{2transfer}$. ~~-~~The new location can apply under ~~this~~the GCS Protocol.

~~(f) Installation of new pipelines and construction of new CO_2 injection sites can cause changes in above and belowground carbon stock depending on the type of land use where these facilities are going to be located. In such a case, direct land use change GHG emissions must be calculated using land use change emission factors utilized in the Global Trade Assessment Project model or using similar CARB-approved land use change emission factors. Direct land use change emissions must be amortized over a period of 30 years. If CCS projects utilize existing pipeline and CO_2 injection infrastructure where land use change have already occurred, direct land use change emissions are considered part of the baseline and are not considered. Indirect land use change GHG emissions are omitted from the Accounting Requirements since they are considered negligible.~~

~~(g)~~(v) For the purpose of estimating LCFS CCS credits, data measurement/generation and reporting requirements for energy and chemical inputs are described in Appendix D.

~~3.~~3.3. Invalidation and Buffer Account

(a) LCFS credits issued for verified GHG emissions reductions associated with CCS projects will be invalidated if the sequestered CO_2 associated with ~~them migrates~~the GHG emissions reductions migrate outside the storage complex or is released to the atmosphere.

(b) The amount of verified GHG ~~emission reduction~~emissions reductions to be invalidated for a CCS project~~s~~ is equal to the CO_2 leakage from the storage

complex ~~($CO_{2leakage}$),~~occurring after credit issuance, which must be determined in accordance with ~~subsection C.4.3.2 of~~ the GC~~C~~S Protocol, section C.4.3.2.

(c) The following will apply to all CCS projects seeking credit issuance under ~~the~~ sections 95490(h)(3) and (4) of the LCFS.

(1) All CCS projects must have received Permanence Certification under the GCS protocol;

~~(1)~~(2) All CCS projects must contribute a ~~percentage~~number of LCFS credits to the Buffer Account at the time of LCFS credit issuance by CARB; and

~~(2)~~ (3) ~~Sequestered CO_2 must remain within the storage complex for at least 100 years in order to be considered permanently sequestered and subsequently credited; and~~

~~(3) Buffer Account contributions:~~ The CCS project's contribution to the Buffer Account is determined by ~~a~~ Equation 7 using the project-specific risk rating ~~method, outlined in~~from the GCS Protocol Appendix A:~~G.~~

$$Buffer\ Contribution = CO_{2_{injected}} \times GCS\ Site\ Risk\ Rating \times \frac{credits}{MT\ CO_2} \quad (7)$$

Where:

Buffer Contribution	=	Number of credits
$CO_{2\ injected}$	=	Amount of injected CO_2 (MT CO_2).
GCS Site Risk Rating	=	Projects overall risk rating using Equation A.1 from the GCS Protocol Appendix A.

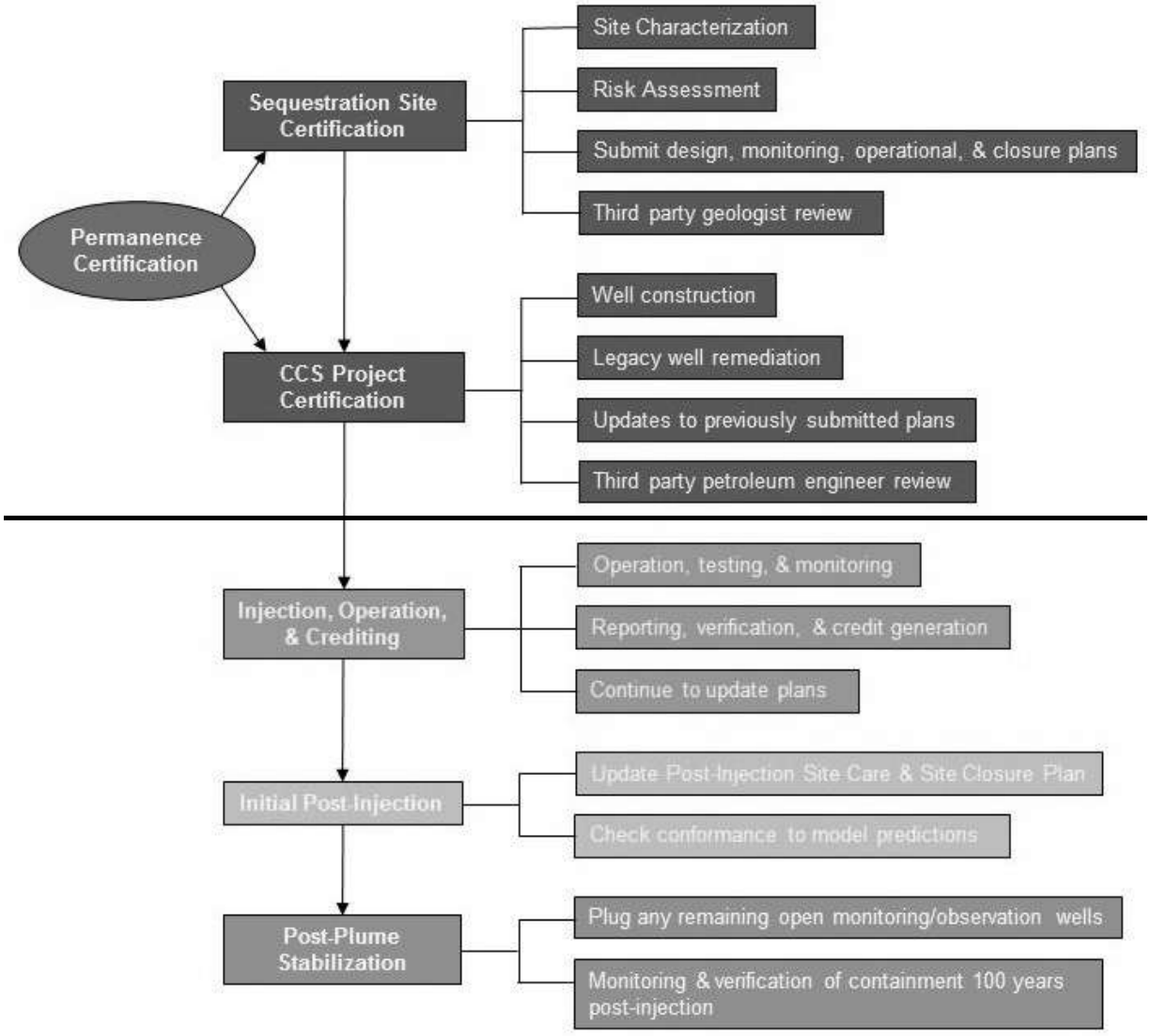
(d) If permanence certification is rescinded, then all sequestered CO_2 is considered released and all LCFS credits issued as a result of the sequestered CO_2 will be invalidated.

~~C. PERMANENCE REQUIREMENTS FOR GEOLOGIC SEQUESTRATION~~

~~1. Permanence Certification of Geologic Carbon Sequestration Projects~~

~~1.1. Application and Certification~~

~~(4) A CCS Project Operator must apply for Sequestration Site Certification pursuant to subsection C.1.1.2(b) and CCS Project Certification following subsection C.1.1.2(d), which are collectively called Permanence Certification. The application must include the third-party review, data, and plans specified in subsections C.1.1.1 and C.1.1.2. A flow diagram depicting the application process for a typical CCS project is shown in Figure 3, below.:~~



~~Figure 3.~~ ~~CCS Protocol certification, operation, and closure process.~~

(a) If after reviewing the submitted material, the Executive Officer determines that the CCS project meets the specifications for sequestering carbon pursuant to the Permanence Requirements, the Executive Officer will post an initial determination along with the application package for public comment for 15 days, address those comments if considered valid, and then issue a Permanence Certification for the project by executive order.

1.1.1. Third Party Review

(a) Prior to submittal of an application to the Executive Officer for Permanence Certification, the CCS Project Operator must have their application reviewed by a third party or parties that are approved by the Executive Officer. For purposes of evaluating potential for conflict of interest, third parties must disclose to the Executive Officer all services provided to the applicant during the prior 5 years and any services provided within one year following certification. Individuals and firms are prohibited from providing third party review of a Permanence Certification application if they have provided or intend to provide other professional services associated with the CCS project. The applicant is responsible for all costs of the application review.

(b) The third-party reviewer must certify that the data submitted as part of the application in subsection C.(b) are true, accurate, and complete.

(c) The third-party reviewer must certify that the plans submitted as part of the application in subsection C.(d) are sufficiently robust that, in their professional judgment, the CCS project is able to meet the permanence requirements for carbon sequestration.

(d) The third-party reviewer must certify that the Site-Based Risk Assessment submitted as part of the application in subsection C. is accurate and complete, and that the risks identified are either sufficiently monitored or sufficiently remediated in the Emergency and Remedial Response Plan submitted in the application.

(e) Third-party evaluation completed under the provisions of subsection C.1.1.1(b) must be completed by a professional geologist licensed under Chapter 12.5 of Division 3 of the California Business and Professions Code §§ 7800 – 7887, or equivalent professional geologist from another jurisdiction that is approved by the Executive Officer.

(f) Third-party evaluation completed under the provisions of subsection C.1.1.1(c) must be completed by a professional engineer licensed under Chapter 7 of Division 3 of the California Business and Professions Code §§ 6700 – 6799, or equivalent professional engineer from another jurisdiction that is approved by the Executive Officer.

~~1.1.2. Certification Application Materials~~

~~All applications for Permanence Certification, pursuant to the Permanence Requirements, must include the following information:~~

~~(a) General Information Requirements:~~

~~(1) Statement of the primary purpose of the project;~~

~~(2) A brief description of the nature of the business;~~

~~(3) The name, mailing address, and latitude and longitude of the CCS project or well for which the Permanence Certification is submitted;~~

~~(4) The operator's name, address, telephone number, ownership status, and status as a federal, state, private, public, or other entity;~~

~~(5) The activities conducted by the operator which would require it to obtain permits under RCRA, the U.S. EPA UIC program, the NPDES program under CWA, or the PSD program under CAA; and~~

~~(6) The activities conducted by the operator that would require it to obtain any drilling permits, valid access agreements, or any encroachment permits under county or city guidelines, or any federal, state, or local air, water, or restricted land use operating permits.~~

~~(7) A listing of all permits or construction approvals received or applied for and their status under any of the following programs:~~

~~(A) Hazardous Waste Management program under RCRA;~~

~~(B) U.S. EPA UIC program under SDWA;~~

~~(C) NPDES program under CWA;~~

~~(D) PSD program under CAA;~~

~~(E) Nonattainment program under CAA;~~

~~(F) NESHAPS preconstruction approval under CAA;~~

~~(G) Dredge and fill permits under section 404 of Clean Water Act; and~~

~~(H) Other relevant environmental permits such as federal, state, county, or city permits.~~

(b) Application for Sequestration Site Certification:

(1) Site-Based Risk Assessment pursuant to subsection C.2.2, including a Risk Management Plan following subsection C.2.2(c);

(2) The following plans:

(A) A Geologic Evaluation report pursuant to subsection C.2.3, including a Formation Testing and Well Logging Plan following subsections C.2.3.1 and C.2.3.1(a);

(B) A Storage Complex Delineation and Corrective Action Plan pursuant to subsection C.2.4, including a description of the computational model used following subsection C.2.4.1 and the report on the results of the plume extent modeling following subsection C.2.4.2;

(C) Baseline Testing and Monitoring Plan pursuant to subsection C.2.5(a);

(D) Well Construction Plan pursuant to subsection C.3.1(b), Pre-Injection Testing Plan (subsection C.3.2(b)), and a plan describing the proposed operating requirements and restrictions (subsection C.3.3(a));

(E) A Testing and Monitoring Plan pursuant to subsection C.4.1, including plans for mechanical integrity testing (subsection C.4.2), emissions monitoring (subsection C.4.3.1), and monitoring, measurement, and verification of containment (subsection C.4.3.2);

(F) A Well Plugging and Abandonment Plan pursuant to subsection C.5.1;

(G) A Post-Injection Site Care and Site Closure Plan pursuant to subsection C.5.2; and

(H) An Emergency and Remedial Response Plan pursuant to subsection C.6;

(3) The following demonstrations:

(A) A Financial responsibility demonstration pursuant to subsection C.7;

(B) A Legal understanding demonstration pursuant to subsection C.9; and

(C) Any other plans or information required by the Executive Officer in order to evaluate the application for Sequestration Site Certification.

(c) Sequestration Site Certification will be implemented by an executive order from CARB.

(d) Application for CCS Project Certification:

(1) Any updates to information or plans from subsection C.1.1.2(b);

(2) Formation testing and well logging report pursuant to subsection C.2.3.1(k);

(3) Updated storage complex delineation and computational modeling results pursuant to subsection C.2.4.2;

(4) Corrective action report pursuant to subsection C.2.4.3(c);

(5) Baseline testing and monitoring report pursuant to subsection C.2.5(d);

(6) Well construction and pre-injection testing report pursuant to subsections C.3.1(b) and C.3.2(c); and

(7) Any other information required by the Executive Officer that is necessary to evaluate the application for CCS Project Certification.

(e) CCS Project Certification will be implemented by an executive order from CARB.

1.1.3. Reporting

1.1.3.1. Electronic Reporting

(a) The CCS Project Operator must submit to the Executive Officer any reports, submittals, notifications, and records made and maintained by the operator under this Permanence Certification in an electronic format. The accuracy of all electronic submissions must be attested to at the time of submission.

(b) The CCS Project Operator is solely responsible for ensuring that the Executive Officer receives its reports, submittals, notifications, and records as required in this section. For the Executive Officer to be able to deem an electronically submitted report to be valid, the report must be accompanied by a digital signature that meets the requirements of California Code of Regulations, title 2, sections 22000 *et seq*.

1.1.3.2. Quarterly or Annual Reporting

Chapter 4. Monitoring, Reporting, and Verification

4.1. Monitoring Requirements for Quantification

(a) In addition to the Testing and Monitoring Plan required under the GCS Protocol for purposes of permanence certification and compliance, the CCS Project Operator must complete and retain for review by a verifier, or the Executive Officer, a written monitoring plan that meets all the requirements of section 95491.1 of the LCFS Regulation. This may be a single monitoring plan for both the LCFS and CCS Methodology.

(b) The monitoring plan must contain the following items specific to the CCS project:

(1) A list of all relevant parameters to account for all variables required for the calculation of $GHG_{net_reduction}$ in Chapter 3.

(2) Sufficient data capture to ensure that the quantification and documentation of CO_2 sequestered is replicable and verifiable pursuant to the quantification requirements of Chapter 3.

(3) A description of the methods, and an estimate of precision and accuracy of the methods used to measure and quantify CO_2 leakage after credit issuance from the storage complex, as required by this Methodology and GCS protocol.

(4) CCS project monitoring techniques must use calibrated metering equipment such as flow meters, utility meters (gas and electricity), and chemistry analyzers. All devices used for calculating $GHG_{net\ reduction}$ must meet the accuracy, and monitoring and recording frequencies of the LCFS regulation.

(5) Documentations of any assumptions and contingencies.

4.2. Reporting for Verification

(a) For crediting purposes, CCS Project Operators are required to submit quarterly or annual (depending on how often the project elects to undergo verification) project reports and fuel pathway reports[5] of GHG emissions reductions and ongoing monitoring results. ~~-~~Reports must include the quantification of GHG emissions reductions and documentation of CO_2 ~~sequestered~~injected pursuant to the ~~Accounting Requirements~~quantification requirements in ~~section B~~Chapter 3. Data quality management must be sufficient to support quantification and verification of GHG emissions reductions and CO_2 ~~sequestered.~~ injected. Reports must comply with the ~~formatting~~documentation, submittal, and timing

[5] For projects and pathways that elect to report and credit quarterly all references to annual or year/ly in the Methodology should be replaced by quarter/ly.

requiredments in the LCFS ~~regulation.~~ Regulation and should be submitted as part of annual or quarterly reporting pursuant to the LCFS Regulation. Verification may only be conducted after the CCS Project Operator submits the appropriate report and attests that the reported information is true, accurate, and complete.

(b) CCS Project Operators must submit applicable quarterly or annual reports that include:

~~(1) All metered measurements of inputs to GHG emissions reductions as calculated in subsection B.2.2;~~

(1) Data required to complete all the calculations in Chapter 3;

(2) Analysis of the CO_2 stream following ~~subsection C.*4.3.1.1*~~GCS Protocol, section B.2(b); and

~~(3) I~~njection rate and volume pursuant to ~~subsection C.*4.3.1.2*~~(e).

~~*1.1.3.3. Annual Reporting*~~

~~(a)~~(3) ~~For crediting purposes, CCS Project Operators are required to submit annual reports of GHG emissions reductions, project operations, and ongoing monitoring results. Reports must include measurements of relevant parameters sufficient to ensure that the quantification and documentation of CO_2 sequestered is replicable and verifiable pursuant to the Accounting Requirements in~~GCS Protocol, section B ~~and the Permanence Requirements in section C. Data quality management must be sufficient to support quantification and verification of CO_2 sequestered. If there are no changes to the plans, pursuant to subsection C.1.1.3, and if acceptable to the Executive Officer, the CCS Project Operator may submit a report demonstrating how they are following the plans.~~ .3(e).

~~(1) CCS Project Operators must submit annual reports that include:~~

~~(A) Metered measurements of all annual GHG emissions reductions as calculated in subsection B.2.2;~~

~~(B) The results of operational parameters and emissions and containment monitoring pursuant to subsections C.3.4, C.4.3.1, and C.4.3.2;~~

~~(C) A summary of any incidents or changes in operational parameters that triggered a storage complex reevaluation following subsections C.2.4.4, C.*2.4.4.1*, and C.3.4;~~

(D) A summary of any incidents that required implementation of emergency and remedial response pursuant to subsection C.6;

(E) Mechanical integrity testing results of project wells pursuant to subsection C.4.2.1, as well as reports documenting any incidents where the loss of mechanical integrity occurred and a demonstration of the actions taken by the CCS Project Operator to mitigate or repair the well;

(F) Results of pressure fall-off testing of injection wells at least once every five years pursuant to subsection C.*4.3.1.5(*a). Pressure fall-off testing results must be submitted to the Executive Officer in writing within 30 days following the test, and the results of these tests must be amended to the annual report pursuant to subsection C.*4.3.1.5*(e);

(G) A report of any corrective action taken by the CCS Project Operator and a justification for why and how the corrective action was implemented, pursuant to subsection C.2.4.3;

(H) The results of each storage complex reevaluation and a report of the actions taken by the CCS Project Operator as a result of the reevaluation, to be performed no less than once every five years, pursuant to subsection C.2.4.4; and

(I) Any other information required by the Executive Officer.

(b) Reports must comply with the formatting and timing required in the LCFS regulation, and must include an attestation that the information submitted is true, accurate, and complete.

1.1.3.4. Advanced Notice Reporting

(a) Well tests: The CCS Project Operator must give at least 30 days advance written notice to the Executive Officer of any planned mechanical integrity test or workover.

(b) Planned Changes: The CCS Project Operator must give written notice to the Executive Officer, as soon as possible, of any planned physical alterations or additions to the injection project other than minor repair/replacement or maintenance activities. An analysis of any changes to the composition of the injection fluid must be submitted to the Executive Officer for review and written approval at least 30 days prior to injection; this approval may result in a CCS project certification modification.

1.1.3.5. Noncompliance and Event Reporting

(a) In the event of an emergency that falls into the "major" or "serious" emergency category pursuant to subsection C.6.1(b) and requires implementation of response actions pursuant to the Emergency and Remedial Response Plan, subsection C.6, the CCS Project Operator must report to the Executive Officer and any relevant local or state agency (including DOGGR and the California Governor's Office of Emergency Management, if the CCS project is in California), or equivalent. Any information must be provided orally and in an electronic format within 24 hours from the time the CCS Project Operator becomes aware of the circumstances. Such reports must include, but not be limited to the following information:

(1) Any evidence of whether the injected CO_2 stream or associated elevated pressure may endanger public health, or any monitoring or other information which indicates that any contaminant may endanger public health;

(2) Any evidence of noncompliance with a Permanence Certification condition, or malfunction of the injection system, which may cause an uncontrolled release of fluid or gas out of the storage complex;

(3) Any triggering of the shut-off system required in subsection C.3.3(g) (e.g., downhole or at the surface) or incident specified in subsection C.3.4;

(4) Any failure to maintain mechanical integrity;

(5) Pursuant to compliance with the testing and monitoring requirements in subsection C.4.3.2, any uncontrolled release of CO_2 outside of the storage complex that may result in atmospheric leakage; and

(6) Actions taken to implement appropriate protocols outlined in the Emergency Remedial Response Plan (subsection C.6).

(b) A written submission must be provided to the Executive Officer within five business days of the time the CCS Project Operator becomes aware of the circumstances described in subsection C.*1.1.3.5*(a). The submission must contain a description of any noncompliance and its cause, the period of noncompliance, including exact dates and times, and, if the noncompliance has not been corrected, the anticipated time it is expected to continue as well as actions taken to implement appropriate protocols outlined in the Emergency and Remedial Response Plan, and steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

1.1.3.6. Additional Reporting

(a) Noncompliance: The CCS Project Operator must report all instances of noncompliance not otherwise reported in subsection C.*1.1.3.5* with the next

quarterly monitoring report. The reports must contain the information listed in subsection C.*1.1.3.5*(b).

(b) Well plugging and abandonment: CCS Project Operators must submit, in writing, a Notice of Intent to Plug 30 days before plugging any well that is part of the CCS project pursuant to subsection C.5.1(h). If amendments to the Well Plugging and Abandonment Plan are necessary, a revised plan must be submitted with the notice of intent, following subsection C.5.1(i). Within 60 days of plugging, the CCS Project Operator must submit a plugging report pursuant to subsection C.5.1(k).

(c) Other information: When the CCS Project Operator becomes aware of failure to submit any relevant facts in the Permanence Certification or that incorrect information was submitted in a Permanence Certification or in any report to the Executive Officer, the CCS Project Operator must submit such facts or corrected information within 10 days.

(d) Reports must comply with the formatting and timing required in the LCFS regulation, and must include an attestation that the information submitted is true, accurate, and complete.

1.1.4. Recordkeeping

(a) The CCS Project Operator must retain records and all monitoring information, including all calibration and maintenance records and all original chart recordings for continuous monitoring instrumentation and copies of all reports required by the Permanence Certification (including records from pre-injection, active injection, and post-injection phases) for a period of 10 years after site closure.

(b) The CCS Project Operator must maintain records of all data required to complete the Permanence Certification and any supplemental information (e.g. modeling inputs for storage complex delineations and plume extent reevaluations, plan modifications, etc.) submitted under subsection C.1.1.2 and reports submitted under subsection C.1.1.3, for a period of at least 10 years after site closure.

(c) The CCS Project Operator must retain records concerning the nature and composition of all injected fluids until 10 years after site closure.

(d) The CCS Project Operator must retain records and all monitoring information for the post-injection site care and monitoring period for at least 10 years after site closure (see subsection C.5.2).

(e) The retention periods specified in subsections C.1.1.4(a) and C.1.1.4(b) may be extended by request of the Executive Officer at any time. The CCS Project Operator must continue to retain records after the retention period specified in subsections 1.1.4(a) and 1.1.4(b) or any requested extension thereof expires

unless the operator delivers the records to, or obtains written approval from, the Executive Officer to discard the records.

1.2. Terms and Conditions

(a) Any changes to the operational parameters of a Permanence Certification are subject to approval by the Executive Officer and must be noted in either an addendum to the Permanence Certification or a revised Permanence Certification.

(b) The Permanence Certification is non-transferable.

(c) Permanence Certification must expire, and be deemed null and void, upon the first day following 24 consecutive months of no injection at the GSC project, and a new approval process and re-certification would be required prior to restarting injection.

2. Site Characterization

2.1. Minimum Site Selection Criteria

(a) As part of the application for Sequestration Site Certification, the CCS Project Operator must demonstrate that the geologic system comprises:

(1) A sequestration zone of sufficient volume, porosity, permeability, and injectivity to receive the total anticipated volume of the CO_2 stream;

(2) A minimum injection depth of 800 m (2,600 ft), or the depth corresponding to pressure and temperature conditions where CO_2 exists in a supercritical state (>31°C and >7 MPa);[6]

(3) A confining system free of transmissive faults or fractures and of sufficient areal extent, integrity, thickness, and ductility to contain the injected CO_2 stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the primary confining layer; and

(4) A confining system composed of a layered interval of low and moderate permeability rocks that will (1) dissipate any excess pressure caused by CO_2 injection, (2) impede vertical migration of CO_2 and/or brine above the storage complex, potentially to the surface and atmosphere via possible leakage

[6] Lin, H., Takashi, F., Reisuke, T., Takahashi, T., and Hashida, T., Experimental evaluation of interactions in supercritical CO_2/water/rock minerals system under geologic CO_2 sequestration conditions (2008) Journal of Materials Science, v. 43, n. 7, p. 2307–2315.

paths, and (3) provide opportunities for monitoring, measurement, and verification of containment.

(5) Depending on the distance between the sequestration zone and basement rock, the Executive Officer may require the CCS Project Operator to identify and characterize additional dissipation interval(s) below the storage complex to limit the extent of downward overpressure propagation and lower the potential for induced seismicity within formations beneath the injection zone.

2.2. Risk Assessment

(a) As part of the application for Sequestration Site Certification, the CCS Project Operator must complete a Site-Based Risk Assessment that quantifies the risk of CO_2 leakage over 100 years post-injection, and describes the potential pathways for leaks or migration of CO_2 out of the storage complex and the potential scenarios that could occur as a result. The results of the risk assessment must be used to inform and design the Testing and Monitoring Plan (subsection C.4.1).

(b) At a minimum, the risk assessment must examine 1) leakage risk, and 2) the scenarios in the Emergency and Remedial Response Plan under subsection C.6.1. Any other risks that could be reasonably anticipated must be included.

(c) The CCS Project Operator must develop and submit a Risk Management Plan (RMP) with the Site-Based Risk Assessment that documents the results of the risk analysis. The RMP must summarize the activities evaluated for risk, what those risks are, how they are ranked, and the steps the CCS Project Operator will take to manage, monitor, avoid, or minimize those risks. Any risk scenarios identified as important but not included in the Emergency and Remedial Response Plan must be included in the RMP.

(d) The operator must use appropriate tools to characterize potential risks of adverse impacts on the environment, health, or safety, by combining the assessment of the probability of occurrence and the magnitude of the adverse impacts of identified project risk scenarios. Risk scenarios identified as part of this assessment must be classified high risk, medium risk, or low risk, according to the combination of probability of occurrence during a 100-year period and the severity of potential consequences (see Table 1, below). The severity of potential consequences identified as part of this assessment must be classified as having a consequence that is insubstantial, substantial, or catastrophic. Any classification of probability of occurrence or severity of potential consequences must be accompanied by a sufficient explanation.

Table 1. Risk scenario classification

	Insubstantial[2]	**Substantial**[2]	**Catastrophic**[2]

> 5%[1]	Medium risk	High risk	High risk
1-5%[1]	Low risk	Medium risk	High risk
< 1%[1]	Low risk	Medium risk	Medium risk

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

(e) Any risk scenarios that are classified as high risk under subsection C.2.2(d) must be mitigated such that they can be re-classified as medium or low risk. Any CCS project with risk scenarios that are classified as high risk that cannot be mitigated to medium or low risk will not be granted Permanence Certification. Risk scenarios classified as high or medium risk must be included in a CCS project's Emergency and Remedial Response Plan.

(f) Risks of CO_2 leakage must be evaluated using the same techniques required in subsection C.2.4.1. Only sites in which the fraction of CO_2 retained in the storage complex is very likely (greater than 90% probability of occurrence) to exceed 99% over 100 years post-injection will be eligible to receive Permanence Certification. Uncertainties identified during site characterization and well installation must be inventoried, and the impact of the uncertainties on storage permanence must be evaluated. Uncertainties that have a material impact on storage permanence must be inventoried and incorporated into the risk assessment, and be used to design monitoring that will reduce leakage risk. Examples of possible material uncertainties include, but are not limited to:

(1) High permeability zones that may lead to horizontal CO_2 leakage;

(2) Natural or well-related flaws in the confining system that may allow vertical CO_2 leakage;

(3) Compartmentalization of the sequestration zone that may lead to elevated pressure; and

(4) Geomechanically sensitive features that may be activated by pressure changes and increase risk of unacceptable seismicity.

2.3. Geologic and Hydrologic Evaluation Requirements

(a) CCS Project Operators are required to submit, with the application for Sequestration Site Certification, an evaluation of the geological and hydrological characteristics of the sequestration zone and confining system derived from academic journals, historical records, laboratory and field data such as geologic

~~core samples, outcrop data, well logs, two- and three-dimensional seismic surveys, and names and lithologic descriptions. The CCS Project Operator must submit the following information:~~

~~(1) Regional geologic information:~~

~~(A) A brief synopsis of the geologic history of the CCS project site;~~

~~(B) Porosity, permeability, lithofacies, depositional environment, and the geologic names and ages of formations;~~

~~(C) Regional hydrogeology of the sequestration zone, including all available data pertaining to groundwater flow direction, flux, and flow patterns; and~~

~~(D) 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.~~

~~(2) Site-specific geologic and hydrogeologic information:~~

~~(A) Depth interval of confining system and sequestration zone below ground surface and depth interval of planned completion interval;~~

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

~~(C) 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;~~

~~(D) Confining system and sequestration zone thickness, as well as total thicknesses of the confining layer(s) and the sequestration reservoir, thicknesses of any high permeability or porosity intervals in the sequestration zone (if applicable), and thicknesses of planned perforated interval(s); and~~

~~(E) Porosity, permeability, and capillary pressure of the sequestration zone, confining layer(s), and location of the completion interval. These data must be used in the calculation of the following properties of the sequestration zone and confining layer:~~

~~1. Hydraulic conductivity;~~

~~2. Specific storage; and~~

3. Storage coefficient.

(3) Site-specific geomechanical and petrophysical information:

(A) Fracture/parting pressure of the sequestration zone and primary confining layer, and the corresponding fracture gradients determined via step rate or leak-off tests performed in the wellbore. For new CCS projects, these testing and logging activities may be undertaken during the drilling of a stratigraphic test well, or during the drilling and construction of any new injection, production, observation, or monitoring well;

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

(C) Rock strength and the ductility of the confining layer(s). Rock strength is usually determined by performing a triaxial load test of the uniaxial compressive strength (*UCS*) on a core sample. Ductility and rock strength must be assessed via the following equations:

1. Ductility of the confining layer(s) must be calculated using the following brittleness index (*BRI*):

$$BRI = \frac{UCS}{UCS_{NC}} \quad (7)$$

Where *UCS* is the unconfined compressive strength of the confining layer as measured from intact samples, and the UCS_{NC} is the confining layer's compressive strength if it was normally consolidated, as measured from remolded samples that are normally reconsolidated;

2. *UCS* can also be estimated from the pressure wave velocity (V_p) through intact samples or measured *in situ* within the wellbore via the equation:

$$\log(UCS) = -6.36 + \log(0.86V_p - 1172) \quad (8)$$

3. The UCS_{NC} can also be estimated from the effective vertical stress (σ'), where:

$$UCS_{NC} = 0.5\sigma' \quad (9)$$

If *BRI* < 2, the confining layer is sufficiently ductile to anneal any discontinuities. If *BRI* > 2, discontinuities may be open.

(D) Pore pressure, or the measure of *in situ* fluid pressure, formation temperature; and

(E) Estimation of the injection volume and the maximum allowable injection rate and pressure, such that neither the primary confining layer nor the sequestration zone hydraulically fracture during injection, must be based on step rate test results as in subsection C.2.3.1(g).

(4) Injectivity or pump tests of the sequestration zone based on CO_2 reservoir flow modeling using information determined from subsection C.2.3.1(h).

(5) Geologic characteristics of any secondary confining layers above the primary confining layer and below the sequestration zone, as well as characteristics of any dissipation intervals above and below the target sequestration zone and confining layer.

(6) A full description of significant geologic structures, including faults and fractures, which intersect the storage complex and all data relevant to assessing the transmissivity of these features. The CCS Project Operator must include a determination that these features will not interfere with containment, supported by information including, but not limited to:

(A) The location, depth, displacement, and geometry of the fault or fracture;

(B) Data on aperture, cement, and fault gouge;

(C) The orientation of the local state of stress and a full geometric description in support of modeling the response to changes in the state of stress during injection; and

(D) Any additional methods and results of fault stability analyses and comparison to anticipated or modeled pressures during injection.

(7) An evaluation of the seismic history of the proposed sequestration site, including the date, magnitude, depth, and location of the epicenter of seismic sources and 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, following a risk assessment pursuant to subsection C.2.2(e);

(8) A tabulation of readily available information on freshwater aquifers and springs in the surface projection of the storage complex. This information should include:

(A) The numbers, thicknesses, and lithologies of freshwater aquifers, including interbedded and low permeability zones;

(B) Water quality such as TDS, alkalinity, pH, dissolved trace metals, and TOC;

(C) The deepest depth of freshwater aquifers;

(D) Whether any freshwater aquifers in the surface projection of the storage complex are currently accessed for human use; and

(E) The location and distance to nearest water supply well and nearest downgradient water supply well, as well as any water wells and springs in the surface projection of the storage complex.

(9) A tabulation of readily available geochemical data on subsurface formations and formation fluids in and around the storage complex, including:

(A) Reservoir fluid data for the sequestration zone, such as TDS, dynamic viscosity, density, temperature, pH, and information on the potentiometric surface, if available;

(B) 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

(C) For CO_2-EOR and 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.

(10) 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.

(b) Characterization of other injection or production fluids in or near the storage complex:

(1) CCS Project Operator must describe and quantify any fluids injected or produced related to the CCS project, in addition to the injection fluid.

(2) The CCS Project Operator must provide a management strategy for all of the following:

(A) The potential unintentional release of production fluid must be mitigated pursuant to the Emergency and Remedial Response Plan from subsection C.6.1;

(B) Other injection, such as waste water disposal, must be considered in regards to pressure changes and the geomechanical response to such injection; and

(C) Distant parameters, such as production or disposal, should be considered in the boundary conditions of the computational model parameters pursuant to subsection C.2.4.1.

(c) Site-specific maps and cross-sections, including:

(1) Geologic and topographic maps and cross-sections illustrating regional geology, hydrogeology, and geologic structure of the local area;

(2) 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;

(3) Structural contour and isopach maps of the storage complex including all faults and fractures, as well as any lateral containment features;

(4) 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;

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

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

(7) Maps showing the locations of any seismic lines and cross-sections; and

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

(d) Description of 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.

(e) Any additional information requested by the Executive Officer that is necessary to complete the geological and hydrogeological site evaluation.

2.3.1. Formation Testing and Well Logging Program

(a) As part of the application for Sequestration Site Certification, the CCS Project Operator must submit a Formation Testing and Well Logging Plan. The plan must demonstrate to the Executive Officer how the CCS Project Operator will collect the geologic and hydrogeologic data required to show that the selected storage complex is suitable for receiving and containing injected CO_2.

(b) For new CCS projects, the testing and logging activities described in subsections C.2.3.1(d) through C.2.3.1(i) may be undertaken during and after drilling of a stratigraphic test well, or during and after the drilling and construction of any new injection, production, observation, or monitoring well.

(c) For a CO_2 injection well to be transitioned from a pre-existing injection, monitoring, stratigraphic test, or production well, the testing and logging information required by subsections C.2.3.1(d) through C.2.3.1(i) can be provided from previous and ongoing testing and monitoring of the formation and from well tests and logs conducted during the previous use of the well.

(d) For existing CCS projects, historical data that provides a demonstration of the suitability of the selected storage complex for sequestering CO_2 may be submitted in lieu of the data required by subsections C.2.3.1(b) and (c), provided the data is determined by the Executive Officer to be equivalent or better than that required by those same subsections.

(e) Well logging requirements:

(1) During the drilling and construction of a CCS project injection well, the CCS Project Operator must run appropriate logs, conduct surveys, and perform tests to determine or confirm the depth, thickness, porosity, permeability, lithology, and salinity of all relevant geologic formations.

(2) Well logging activities must be used to supplement data on the geologic and hydrogeologic properties of relevant subsurface formations collected during initial site characterization and to support building a conceptual understanding of the site, conducting the storage complex determination, and designing the CCS project.

(3) Well logging results must also be used to establish baseline data against which to compare to future measurements under subsection C.2.5, and to ensure conformance with the injection well construction requirements under subsection C.3.1.

(4) CCS Project Operators must use well logging results to create a temperature vs. depth and hydrostatic pressure profile, which should be used to inform the risk evaluation (subsection C.2.2) and monitoring (subsection C.4.3).

(f) Core analyses:

(1) The CCS Project Operator must take whole cores or sidewall cores of the sequestration zone and primary confining layer, and formation fluid samples from the sequestration zone, during drilling and prior to well construction. The cores of the sequestration zone and primary confining layer must be collected during the initial stages of project development, from a stratigraphic well or from the injection well itself, pursuant to the needs of the operator. The CCS Project Operator must submit to the Executive Officer a detailed report prepared by an experienced log analyst that includes: well log data and analyses (including the logs themselves), core analyses, and formation fluid sample information.

(2) Information from cores must be used to refine site characterization data submitted pursuant to subsection C.1.1.2.

(3) The Executive Officer may accept information on cores from nearby wells that were previously collected if the CCS Project Operator can demonstrate that core retrieval is not possible and that such cores are representative of conditions at the well site.

(4) Core logs must include descriptions or indications of the following characteristics: lithology, thickness, grain size, sedimentary structures, diagenetic features, geologic contacts, textural maturity, oil staining, fracturing, and porosity.

(5) Laboratory analysis of cores must include petrology and mineralogy, petrophysical properties, and geomechanical properties, including but not limited to, relative permeability, capillary pressure, fluid compatibility, wettability, and pore volume compressibility.

(6) The Executive Officer may require the CCS Project Operator to take core samples of other formations in the wellbore, such as dissipation intervals or secondary confining layers in the stratigraphic column, in order to characterize the mitigation potential of over- and underlying geologic formations.

(g) Characterization of the chemical and physical properties and downhole conditions of fluids in the sequestration zone:

(1) Upon completion of the injection well and prior to operation, the CCS Project Operator must collect data on downhole conditions needed to support monitoring and computational modeling design. The CCS Project Operator must justify the sufficiency of the data collected, and that the method by which it was collected and analyzed is suitable for the purposes to which it is applied. Data required include fluid temperature, pH, conductivity, reservoir pressure, and fluid density.

(2) If geochemical data are to be used for monitoring, a site-specific procedure to separate leakage signal from background must be developed. For example, dissolved gases must be assessed with correction for pressure and temperature effects; and

(3) The CCS Project Operator must submit the results of all downhole analyses and any laboratory results on samples, including quality assurance samples (e.g., blanks, duplicates, matrix spikes).

(h) Fracture/parting pressure of the sequestration zone and primary confining layer:

(1) The CCS Project Operator must perform step rate tests for each CO_2 injection well that is part of the CCS project, and use the results of each test to determine the fracture pressure of the sequestration zone and primary confining layer.

(A) The CCS Project Operator must report the results of all step rate tests for each CO_2 injection well. Such data must be used to determine the maximum allowable injection pressure for the CCS project such that injection will not initiate or propagate faults of fractures in the sequestration zone or primary confining layer; and

(B) Step rate tests must meet the following requirements:

1. Real-time downhole pressure recording must be employed;

2. Bottom-hole pressure must be recorded at a zero injection rate for at least one full time step before the first step of the step rate test, and before one full time step after the last step of the step rate test; and

3. Step rate test data reported under subsection C.1.1.2 must be raw and unaltered, and include the injection rate, bottom-hole pressure, surface pressure, pump rate volume, and time recorded continuously at a rate of every one second during the step rate test.

(2) The CCS Project Operator must also discuss how the calculated fracture pressure compares with data from core tests or other wells in the area, if available.

(i) Hydrogeologic testing:

(1) Upon completion of the injection well, prior to operation, the CCS Project Operator must conduct at least one of the following transient analysis tests to determine hydrogeologic characteristics of the sequestration zone:

(A) A pressure fall-off test;

(B) A pump test; or

(C) Injectivity tests.

(2) These tests must be designed to determine the injectivity of the sequestration zone to set operating limits for CO_2 injection rates and volumes; and

(3) Pressure fall-off tests must be conducted to determine hydrogeologic parameters, including but not limited to, the transmissibility of the sequestration zone, the static sequestration zone pressure, the skin factor, and to identify faults or fractures adjacent to the wellbore.

(j) The CCS Project Operator must determine or calculate any additional physical and chemical characteristics of the sequestration zone and confining system needed to augment other information gathered during the site characterization process, support the development of the storage complex delineation and plume extent model, or support setting of permit conditions (e.g., operational limits).

(k) The CCS Project Operator must provide the Executive Officer, or delegate, with the opportunity to witness all logging and testing in this subsection. A state licensed engineer, or equivalent, may be allowed to witness logging and testing, if approved by the Executive Officer.

(l) The CCS Project Operator must submit a descriptive report that includes an interpretation of the results of the formation testing and well logging program with the application for CCS Project Certification. At a minimum, the report must include:

(1) The results of each test, log, and any supplemental data;

(2) 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;

(3) Any changes in interpretation of site stratigraphy based on formation testing and well logs; and

(4) A description of any alternative methods used that provide equivalent or better information, and that are required and approved by the Executive Officer.

(5) The CCS Project Operator must 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. The Executive Officer may compare the results of formation testing logs from different wells in the vicinity to interpret local stratigraphy, and confirm the depths and properties of the proposed sequestration zone and confining system.

2.4. Storage Complex Delineation and Corrective Action

(a) The storage complex delineation and corrective action requirements are to ensure that the surface areas and subsurface volumes potentially impacted by a proposed GSC project are delineated, all wells that need corrective action receive it, and that this process is updated throughout the active life of the CCS project. The general relationship between site characterization, risk assessment, modeling, monitoring, risk management, quantification, and reporting activities at a CCS project is shown on .

(b) The basic requirements of the storage complex delineation effort and corrective action requirements are as follows:

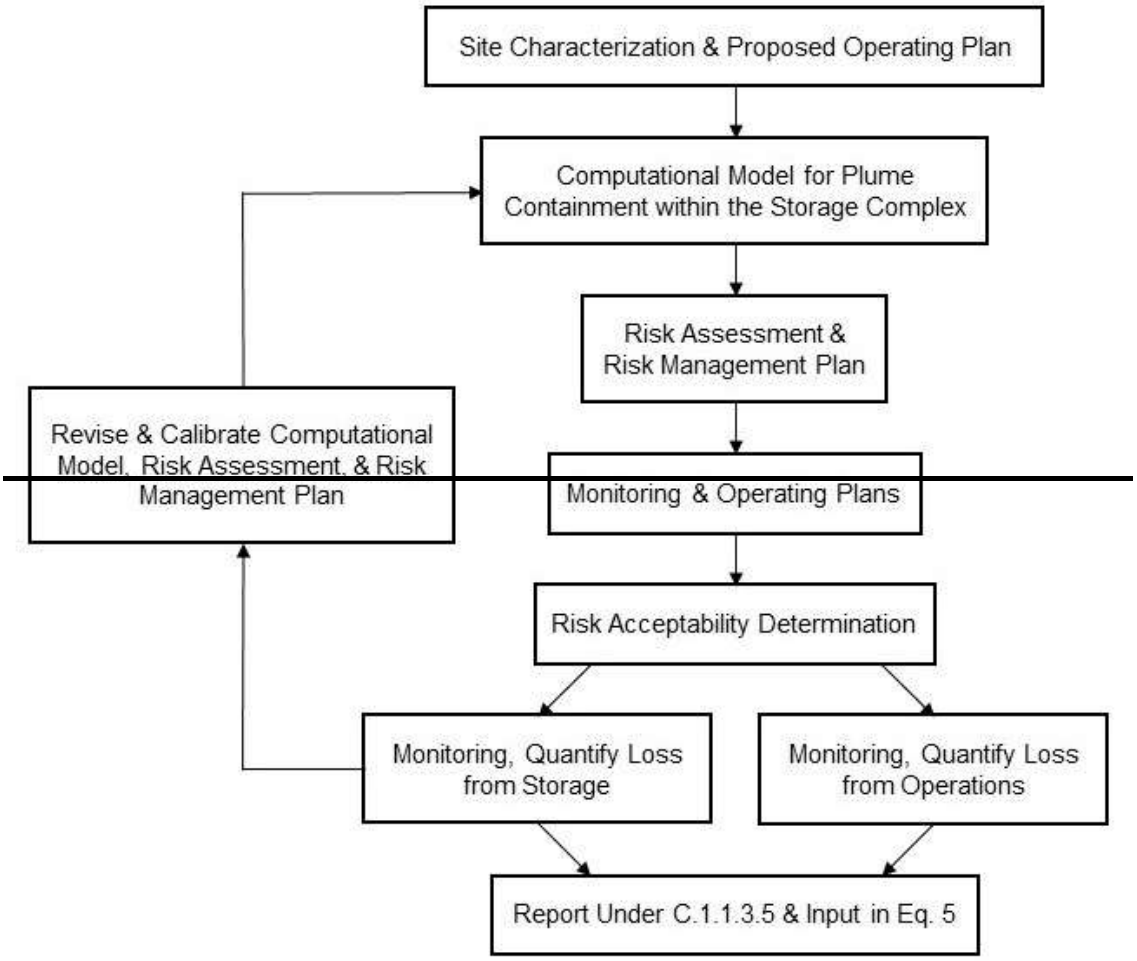


Figure 4. Flow chart showing the process for CCS project design.

(1) The CCS Project Operator must prepare, maintain, and comply with a plan to delineate the storage complex for a proposed CCS project, periodically reevaluate the delineation, and perform corrective action that meets the requirements of this section and is acceptable to the Executive Officer, which includes the following:

(A) Delineate the storage complex using computational modeling as discussed in subsection C.2.4.1, based on available site characterization, monitoring, and operational data;

(B) Identify all wells that penetrate the storage complex and that require corrective action pursuant to subsections C.2.4 and C.*2.4.3.1*;

(C) Perform corrective action on all wells that may be potential vectors for CO_2 leakage, including wells that either (1) penetrate the storage complex, or (2) are within the surface projection of the storage complex, pursuant to subsections C.2.4(b)(2) and C.2.4.3, and the risk assessment in subsection C.2.2.;

(D) Reevaluate the retention and containment of the CO_2 plume within the storage complex throughout the life of the CCS project following subsection C.2.4.4;

(E) Ensure that the Emergency and Remedial Response Plan and financial responsibility demonstration account for the approved storage complex delineation; and

(F) Retain all modeling inputs and data used to support initial storage complex delineations and plume extent reevaluations of the retention and containment of the CO_2 plume within the storage complex for the life of the CCS project and 10 years following site closure.

(2) Storage Complex and Corrective Action Plan:

(A) As a part of the application for Sequestration Site Certification, the CCS Project Operator must submit an Storage Complex Delineation and Corrective Action Plan that includes the following information:

(B) The method for delineating the storage complex that meets the requirements of subsection C.2.4, including a detailed report on the computational model used, assumptions made, and site characterization data on which the computational model will be based; and

(C) A description of:

1. The minimum fixed frequency, not to exceed five years, at which the CCS Project Operator will reevaluate the extent of the plume and a justification for the proposed reevaluation frequency;

2. How monitoring and operational data (e.g., injection rate and pressure) will be used to inform a plume extent reevaluation; and

3. How corrective action will be conducted to meet the requirements of subsection C.2.4, including 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.

2.4.1. Computational Modeling Requirements

(a) The CCS Project Operator must delineate the storage complex and perform a risk assessment that shows that the storage complex will contain the CO_2 plume over the life of the project and for a minimum of 100 years post injection (see subsection C.2.2). Any time the CCS Project Operator performs computational modeling under this subsection, the modeling must encompass the timeframe from the beginning of the project through 100 years post-injection. The risk assessment must be based on a computational model that accounts for the physical properties and site characteristics of the sequestration zone and injected CO_2 stream over the proposed life of the CCS project and prepare a report on the outcomes via the following actions:

(1) The computational model of the storage complex must incorporate various parameters including site characterization, monitoring, operational data, and:

(A) Predict the lateral and vertical migration of the free-phase CO_2 plume and elevated pressure, as well as the dissolved CO_2 plume in the subsurface, from the commencement of injection activities until plume stabilization;

(B) Be designed to simulate multiphase flow of several fluids (groundwater, CO_2, and hydrocarbons, if present), phase changes of CO_2, significant pressure changes, and any other pertinent processes in geologic media based on scientific principles and accepted mathematical and governing equations;

(C) Be based on detailed geologic, hydrogeologic, and geomechanical data collected for the characterization of the sequestration zone and confining layer(s). The CCS Project Operator must consider and report on the justification for the following list of inputs when designing the computational model and must conduct and report on sensitivity analyses and provide justification for all simplifications selected, based on site-specific conditions:

1. Regional and site-specific geology, such as stratigraphy, formation lithology, elevation, thickness, and structural geology (including faults, folding, fractures). This data must be used to justify all boundary conditions selected for the computational model that are relevant to pressure management during injection;

2. Reservoir conditions including (1) hydrogeologic conditions such as intrinsic and relative permeabilities, porosity, capillary pressure, formation compressibility, water saturation, CO_2 saturation, and storativity, and (2) reservoir fluid properties such as brine or hydrocarbon viscosity, density, composition or salinity, and compressibility;

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: (1) initial conditions (e.g., fluid composition and distribution, etc.) within the domain at the beginning of the model run, (2) time steps and a justification for the selection, (3) vertical and horizontal gridding design and a justification that they are fit-to-purpose, and (4) 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. For example, mineral precipitation kinematic parameters may be introduced into a reactive transport model of the reservoir if the planned injectate and composition of water at depth are predicted, based on sampling and monitoring data, to react such that mineral precipitation may modify the permeability of the reservoir. For injection into depleted reservoirs or CO_2-EOR operations, the measurements and computational assumptions (e.g., "black oil" or compositional model) made about the CO_2-fluid interactions must be specified, sensitivity analysis conducted, and the selected approaches justified;

(D) Parameter values must be based on site data to the best extent possible. In cases where certain detailed site geologic characterization data are unavailable, parameter values may be estimated from standard values or relationships in the scientific literature. CCS Project Operators must indicate the range of values possible for their site and conditions, and must provide a justification for using each particular parameter value not directly measured in the field or the laboratory. Probability and statistical methods of distributing attributes should be documented and sensitivity analyses performed;

(E) All data collected to comply with site characterization requirements must be considered in the storage complex delineation. Any additional data

~~available in the vicinity of the site that may affect the storage complex delineation, e.g., from the U.S. Geological Survey or other wells drilled within the vicinity of the storage complex must also be considered in model development. Simplifications must be documented and justified;~~

~~(F) Utilize and document appropriate equations of state and constitutive relationships derived from equilibrium phase relationships and empirically based approximations, respectively;~~

~~(G) Explicitly 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;~~

~~(H) Describe and justify the method and assumptions used to history match the pressure distribution;~~

~~(I) Take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions;~~

~~(J) Modeling must consider potential migration through faults, fractures, and artificial penetrations, and determine the detectable response to such leakage. The outcomes of these models must be included in the risk assessment, monitoring and testing plans, and proposed operations; and~~

~~(K) Perform sensitivity analysis on model input parameters and qualify the model by assessing the implications of uncertainties in input data to the model predictions. Any material uncertainties that could result in the loss of permanent storage must be considered, and models showing the impact of uncertainties must be incorporated into the risk assessment to determine how the uncertainties can be detected by monitoring.~~

~~(2) The computer code(s) requirements:~~

~~(A) Computer code(s) utilized in the storage complex delineation and plume extent modeling must be:~~

~~1. Validated for use in peer-reviewed literature;~~

~~2. Available to CARB and CCS Project Operators during CARB's review of any permanence certification application, and preferably open source; and~~

~~3. Validated by a third party approved by the Executive Officer and applicant. Third-party validation must occur any time the CCS Project Operator submits an application for certification or recertification by~~

~~CARB, including: Sequestration Site Certification, CCS Project Certification, Plume extent reevaluations pursuant to subsection C.2.4.4(b), and approval of plume-stability pursuant to subsection C.5.2(b).~~

~~(B) The code(s) used for modeling the storage complex must demonstrate 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.~~

~~(C) Techniques to demonstrate that the code(s) is appropriate include:~~

~~1. Successful application in a similar setting leading to successful history matching;~~

~~2. Comparison of a new code against a proven code to show reasonable match; or~~

~~3. Sensitivity studies showing that the code reproduces the relevant physics properly.~~

~~(D) Codes must properly manage key properties of the reservoir fluid system, including three-dimensionally heterogeneous formations, and characteristic-curve hysteresis and residual phase trapping. If important, mineral precipitation/dissolution reactions and subsequent mineral phase trapping or leaching of heavy metals may be considered. The system response to leakage through faults, fractures, and wellbores must be modeled, and results used for the risk assessment and testing and monitoring design; and~~

(E) If using a non-peer-reviewed independently developed or untested code, the developer must validate the model's appropriateness by modeling validated test cases of problems with similar physics found in the literature before submitting the application for Sequestration Site Certification.

2.4.2. Storage Complex Delineation using Computational Modeling Results

(a) The initial storage complex delineation and plume extent model must be submitted with the proposed Storage Complex and Corrective Action Plan in the application for Sequestration Site Certification pursuant to subsection C.1.1.2(b). The model must be updated using all additional characterization and pre-injection testing data, and finalized prior to obtaining CCS Project Certification following subsection C.1.1.2(d). Versions of the model must be given unique identifiers.

(b) The storage complex boundaries must be based on simulated predictions of the lateral extent of the separate-free-phase CO_2 plume and elevated pressure until it stabilizes after the end of injection for the cumulative CCS project model, and must account for the anticipated injection rates from all planned injection and production (if applicable) wells.

(c) A single modeling exercise must be conducted for all wells within a single CCS project.

(d) The application for Sequestration Site Certification submittal must include the following in support of the storage complex delineation:

(1) 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;

(2) A description of 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;

(3) An accounting of all equations of state used for all modeled fluids (groundwater, CO_2);

(4) Any constitutive relationships, such as relative-permeability saturation relationships, and how they were determined; and

(5) Model results, including predictions of the free-phase CO_2 plume extent and elevated pressure over the lifetime of the CCS project. Model results must be presented in contour maps, cross sections, and/or graphs showing the CO_2 plume extent and elevated pressure as a function of time, and the application

for Sequestration Site Certification submittal must include the outcome of parameter sensitivity analysis and model calibration.

2.4.3. Corrective Action Requirements

(a) Corrective Action Plan:

(1) The CCS Project Operator is required to submit a Corrective Action Plan with the initial application for Sequestration Site Certification pursuant to subsections C.1.1.2 and C.2.4.3(a). The Corrective Action Plan must describe:

(A) Methods for the identification of all artificial penetrations that either penetrate the storage complex or are within the surface projection of the storage complex;

(B) 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; and

(C) The schedule of corrective action activities that minimizes risk to public health and the environment.

(b) Following Executive Officer approval and pursuant to the Corrective Action Plan, CCS Project Operators of CO_2 injection wells must perform the following actions:

(1) Use best available methods and technologies to identify all artificial penetrations, including all wells that either penetrate the storage complex or are within the surface projection of the storage complex, and provide a tabulation of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, casing diagrams for those wells pursuant to subsection C.*2.4.3.1*, and any additional information the Executive Officer may require; and

(2) Use a variety of methods to identify all wells that either penetrate the storage complex or are within the surface projection of the storage complex that require corrective action, such as those that are improperly plugged or abandoned such that they may leak gas or fluid, or those that are currently leaking gas or fluids, including, but not limited to:

(A) Historical research of state and local databases, county records, and private data;

(B) Site reconnaissance, including interviewing local residents and property owners, as well as conducting a physical search for features indicative of abandoned wells;

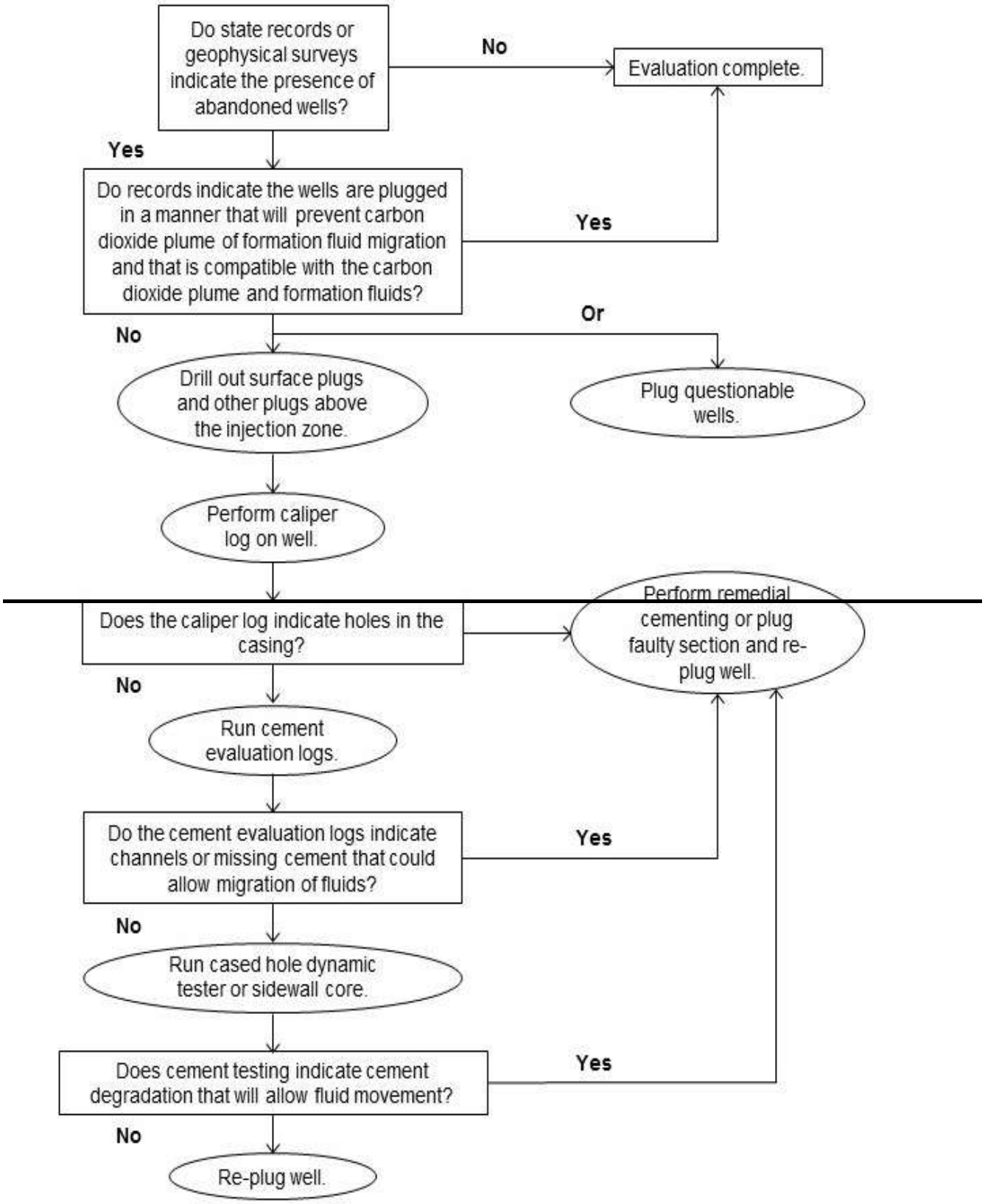
(C) Aerial photography and satellite imagery review;

(D) Geophysical methods including magnetic, ground penetrating radar, and electromagnetic surveys;

(E) Abandoned well plugging records; and

(F) Well field testing, such as the analysis of each well using CH_4 detection equipment.

(c) CCS Project Operators must perform corrective action on all wells that either penetrate the storage complex or are within the surface projection of the storage complex that are determined to need corrective action, including all wells that penetrate the storage complex and are determined to have been plugged and abandoned in a manner such that they could serve as a conduit for fluid movement into the shallower subsurface, prior to the commencement of injection. Figure 5 presents a flow chart that illustrates how the various evaluation tools must be used together to evaluate abandoned wells. CCS Project Operators must submit a descriptive report with the application for CCS Project Certification that demonstrates how corrective action was applied to deficient wells. Any historical records search must include a description of the completeness of state or federal databases.



~~Figure 5~~. ~~Well evaluation flow chart.~~

(d) Prior to CCS Project Certification, CCS Project Operators must perform corrective action on all wells that either penetrate the storage complex or are within the surface projection of the storage complex that require corrective action. In performing corrective action, CCS Project Operators must use methods designed to prevent the movement of fluid out of the storage complex into a shallower zone, including use of materials compatible with the CO_2 stream, where appropriate.

(1) A well requires plugging if:

(A) Records indicate that a well plug sufficient to prevent upward movement of fluids does not exist at a depth corresponding to the primary confining layer, or there are no well plugs below permeable formations that may exhibit cross flow of mobilized fluids along the wellbore or casing; or

(B) Field evaluations reveal cracks, channels, or annuli in the plug that would allow fluid migration or suggest the plug material may corrode in response to reactions with CO_2; or

(C) Field tests indicate the well is leaking gas or fluids.

(2) A well requires remedial cementing if records or field evaluations indicate that the cement surrounding the wellbore has failed or has cracks, channels, or annuli that could allow migration of CO_2, or if the well has not been cemented.

(3) Materials used for cementing of abandoned wells must be supplemented with or replaced by materials such as polymer gels and acrylic grouts, if required by the Executive Officer.

(e) If corrective action is warranted during the injection or post-injection period based on a storage complex reevaluation pursuant to subsection C.2.4.4, the CCS Project Operator is required to take the following actions:

(1) Identify all wells or features that either penetrate the storage complex or are within the surface projection of the storage complex that require corrective action;

(2) Identify the appropriate corrective action the well or feature requires pursuant to subsection C.2.4.3;

(3) Prioritize corrective actions to be performed; and

(4) Conduct corrective actions under a schedule that minimizes risk to public health and the environment.

2.4.3.1. Casing Diagrams of Wells Penetrating the Confining System

(a) Casing diagrams submitted under subsection C.2.*4.3.1* must demonstrate that the wells will not be potential conduits for CO_2 or fluid leakage or otherwise have any adverse effects on the CCS project or cause damage to public health or the environment, and must meet the following requirements:

(1) Casing diagrams must include the following data to the extent known:

(A) Operator name, lease name, well number and API number of the well;

(B) Ground elevation from sea level;

(C) Reference elevation (i.e. rig floor or Kelly bushing);

(D) Base of freshwater;

(E) Sizes, grades, connection type, and weights of casing and tubing;

(F) Depths of casing shoes, stubs, and liner tops;

(G) 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;

(H) Information regarding associated equipment such as subsurface safety valves, packers, and gas lift mandrels;

(I) Diameter and measured and true vertical depth of wellbore;

(J) Wellbore path that includes inclination and azimuth measurements;

(K) Cement plugs inside casings, including top and bottom of cement plug, with measuring method indicated;

(L) Cement fill behind casings, including top and bottom of cement fill, with measuring method indicated;

(M) Type and density of fluid between cement plugs;

(N) Depths and names of the formations, zones, and sand markers penetrated by the well, including the top and bottom of the zone where injection will occur;

(O) All steps of cement yield and cement calculations performed;

(P) 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

(Q) 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.

(2) Casing diagrams must be submitted as both a graphical diagram and as a flat file data set.

(3) Any additional information that the Executive Officer may require.

2.4.4. Plume Extent Reevaluation

(a) Every five years, or when monitoring and operational conditions warrant pursuant to subsection C.*2.4.4.1*, CCS Project Operators must update and validate the computational model, reevaluate the size and shape of the CO_2 plume in the manner specified in subsections C.2.4, C.2.4.1, and C.2.4.2, and determine if the plume is within the storage complex;

(b) To reevaluate the computational model, CCS Project Operators must take the following steps:

(1) Review monitoring data and compare it to model predictions to assess whether the predicted CO_2 plume geometry and elevated pressure is consistent with actual data;

(2) Review operating data to validate that it is consistent with the inputs used in the reevaluation of the modeling effort;

(3) Review any new geologic data acquired since the last modeling effort and identify if any new data materially differ from that input into the model;

(4) Modify model input parameters and recalibrate the model using the results of subsections C.2.4.4(b)(1) through C.2.4.4(b)(3);

(5) Rerun the model to determine if the CO_2 plume is predicted to stay within the storage complex until the end of the post-injection site care and monitoring period;

(6) Have a third-party validate the reevaluated model pursuant to subsection C.2.4.1(a)(2); and

(7) If necessary, reevaluate the injection plan, the project accounting, or the storage complex delineation, risk assessment, and monitoring plan.

(c) If the information reviewed is consistent with, or unchanged from, the most recent modeling assumptions, or confirms modeled predictions about the maximum extent of CO_2 plume and elevated pressure, the CCS Project Operator must prepare a report demonstrating that no corrective action is needed. The report must include the data and results demonstrating that no changes are necessary;

(d) If the CO_2 plume is determined to have migrated outside the storage complex, the CCS Project Operator must take the following actions:

(1) Quantify and verify the amount of CO_2 leakage that occurred, and modify the injection operation to avoid further leakage; and

(2) If the injection operation cannot be modified to avoid further leakage, the CCS Project Operator must cease injection pursuant to subsection C.3.4. The CCS Project Operator may restart injection after re-applying for, and receiving, CCS Project Certification pursuant to subsection C.1.1.2(d), with a newly delineated storage complex for which the operator can avoid further leakage.

(e) If the updated model of the plume extent predicts that CO_2 leakage will occur prior to the end of the post-injection site care and monitoring period, the CCS Project Operator must modify the operation and injection plan such that the modeled plume remains inside the storage complex until stabilization. If the operation cannot be modified such that the modeled plume remains inside the storage complex, the CCS Project Operator must re-apply for, and receive, CCS Project Certification pursuant to subsection C.1.1.2(d), with a newly delineated storage complex for which the operator can avoid the predicted leakage prior to the date by which leakage is predicted to occur.

(f) The Storage Complex and Corrective Action Plan, Emergency and Remedial Response Plan, Testing and Monitoring Plan, Post-Injection Site Care and Closure Plan, and the demonstration of financial responsibility in subsection C.7 must account for the storage complex delineated as specified in subsection C.2.4.2, or most recently evaluated storage complex delineated under subsection C.2.4.4.

2.4.4.1. Triggers for Plume Extent Reevaluations Prior to the Next Scheduled Reevaluation

(a) Unscheduled reevaluations of the CO_2 plume extent must be based on observational or quantitative changes of the monitoring parameters of the CCS project.

(b) Triggers for CO_2 plume extent reevaluations must be developed and quantified as part of the CO_2 plume extent evaluation pursuant to subsection C.2.4.2, based on site-specific risks identified in the Risk Assessment pursuant to subsection C.2.2.

(c) Observations that will trigger an CO_2 plume extent reevaluation include:

(1) Observed migration of the CO_2 plume beyond the acceptable range predicted by the computational model;

(2) Observed shape of the CO_2 plume is not consistent with model predictions, suggesting potential movement of CO_2 outside of the intended formation;

(3) A trend in pressure increase at the injection well(s) or other monitoring points that deviates systematically from the predicted trend; and/or

(4) CO_2 leakage charging a zone above the storage complex;

(d) An unscheduled CO_2 plume extent reevaluation may also be needed if it is likely that the actual free-phase CO_2 plume or elevated pressure extend beyond that modeled because any of the following has occurred:

(1) An earthquake of magnitude 2.7[7] or greater within a one mile radius of the CCS project; or

(2) New site characterization data change the computational model to such an extent that the predicted free-phase CO_2 plume or elevated pressure extends vertically or horizontally beyond that predicted.

(e) Any site-specific criteria that will trigger a CO_2 plume extent reevaluation for a particular CCS project must be included in the Storage Complex Delineation and Corrective Action Plan.

2.5. Baseline Testing and Monitoring

(a) As part of the testing required to meet certification pursuant to subsection C.4, CCS Project Operators must monitor the surface, near-surface, and deep subsurface for CO_2 leakage that (1) may endanger public health or the environment or (2) require reversals of the storage credits due to a failure to achieve and maintain permanence. In order to meet the requirements of subsection C.4, CCS Project Operators must design a baseline testing strategy that supports and informs a testing and monitoring program that is capable of detecting leaks of CO_2 outside of the sequestration zone and storage complex.

[7] Cal. Code Regs., tit. 14, § 1724.14, "Pre-Rulemaking Discussion Draft 04-26-17 Updated Underground Injection Control Regulations," (2017).

(b) Baseline testing and monitoring plan requirements:

(1) The CCS Project Operator must submit a Baseline Testing Plan with the application for Sequestration Site Certification; and

(2) The baseline testing strategy must be sufficient to detect, validate, and quantify potential CO_2 leakage. The baseline testing strategy must also be sufficient to support conclusions about, and validation of, mitigation of CO_2 leakage. The baseline testing strategy must be determined on a site-specific basis consistent with (1) the risk assessment pursuant to subsection C.2.2, (2) the results of computational modeling pursuant to subsection C.2.4.1.

(c) Baseline testing and monitoring data collection and analysis:

(1) The frequency and spatial distribution of baseline data collection must be designed according to a timeline and schedule set forth in the application for Sequestration Site Certification, utilizing no less than one year prior to the initiation of injection;

(2) Baseline data on the physical and chemical conditions of the sequestration zone, confining system, and surface must be collected prior to operation, and must be (1) sufficient to track the three-dimensional evolution of the CO_2 plume, and (2) 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;

(3) Any property of the storage complex, groundwater, overburden, or surface projection of the storage complex that is shown by the risk assessment (pursuant to subsection C.2.2) to potentially be impacted by injection operations must be evaluated, including but not limited to: downhole pressure, sequestration zone fluid chemistry, soil-gas composition, vegetation type and density, and fresh and overburden water chemistry and pressure;

(4) Natural background variability at daily, seasonal, or long duration trends (e.g., climate change, sea level rise, urbanization, or other landscape evolution) must be considered, and may require advanced approaches to separate CO_2 leakage signals from natural changes;

(5) Potential tools CCS Operators may choose to use for baseline testing pursuant to this subsection and testing and monitoring pursuant to subsection C.4.1 include, but are not limited to:

(A) Time-lapse geophysical tools such as seismic, electrical, gravity, and pulse neutron methods;

(B) Soil-gas and air monitoring tools; and

(C) Pressure and chemical tools.

(6) For each method chosen by the CCS Project Operator for baseline testing, the process by which the survey can be accurately repeated in terms of location and instrumentation must be provided.

(d) Baseline testing and monitoring report:

(1) The CCS Project Operator must submit a descriptive report of baseline monitoring data and interpretations with the application for CCS Project Certification. The report must include geophysical, pressure, and chemical data from the subsurface, near surface, and surface analyses, and CCS Project Operators must submit, at a minimum, the following:

(A) 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);

(B) Sampling locations (in map form) and dates sampled;

(C) Atmospheric conditions, if applicable;

(D) Sampling and analytical methods, including detection limits;

(E) Results presented as concentrations and fluxes in tabular and graphic form, including quality assurance (QA) samples and analyses;

(F) Methods and results of any regression analyses; and

(G) Methods and results of any ecological modeling or sensitivity analysis performed, including input data and outputs.

(e) The CCS Project Operator must assess the impact of baseline site characteristics on operational and long term monitoring, and demonstrate that the locations sampled represent a reasonable grid size and determine if potential point sources are represented and if locations will serve as a good baseline to compare to future monitoring data. The CCS Project Operator must also 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 monitoring.

3. Well Construction and Operating Requirements

3.1. Well Construction

(a) General Requirements:

(1) The CCS Project Operator must ensure that all injection, observation or monitoring, and production wells associated with the CCS project are constructed and completed to:

(A) Prevent the movement of fluids into or between any unauthorized zones;

(B) Permit the use of appropriate testing devices and workover tools; and

(C) Permit continuous monitoring of the pressure in the annulus space between the injection tubing and long string casing.

(b) The CCS Project Operator is required to submit a Well Construction Plan with the application for Sequestration Site Certification, pursuant to subsection C.1.1.2.

(c) Casing and cementing of CCS project wells:

(1) Casing and cement or other materials used in the construction of each well associated with a certified CCS project must have sufficient structural strength and be designed for the life of the CCS project. All well materials must be compatible with fluids with which the materials may be expected to come into contact (e.g., corrosion-resistant well casings) and must meet or exceed standards developed for such materials by API, ASTM International, or comparable standards acceptable to the Executive Officer. The casing and cementing program must be designed to prevent the movement of fluids out of the sequestration zone and above the storage complex. In determining and specifying the casing and cementing requirements, the CCS Project Operator must consider the following factors:

(A) Depth to the sequestration zone;

(B) Injection pressure, external pressure, internal pressure, and axial loading;

(C) Hole size;

(D) Size and grade of all casing strings (wall thickness, external diameter, nominal weight, length, joint specification, and construction material);

(E) Corrosiveness of the CO_2 stream and formation fluids;

(F) Downhole temperatures;

(G) Lithology of sequestration and confining layer(s);

(H) Type or grade of cement and cement additives; and

(I) Quantity, chemical composition, and temperature of the CO_2 stream.

(2) Surface casing must extend through the base of the lowermost freshwater aquifer and be cemented to the surface through the use of a single or multiple strings of casing and cement.

(3) At least one long string casing, using a sufficient number of centralizers, must extend to the sequestration zone and must be cemented by circulating cement to the surface in one or more stages. The CCS Project Operator may use an alternate method of cementing if cementing to surface will compromise the integrity of the well or confining layer(s), provided the operator:

(A) Submits a demonstration as part of the Well Construction Plan describing the proposed method of cementing and an explanation for why the particular method was chosen;

(B) Follows best practices that meet or exceed standards developed for such methods and materials by API, ASTM International, or comparable standards acceptable to the Executive Officer; and

(C) Receives Executive Officer approval prior to well construction.

(4) Cement and cement additives must be of sufficient quality and quantity to maintain integrity over the design-life of the CCS project. The integrity and location of the cement must be verified using technology capable of (1) evaluating cement quality radially and (2) 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.

(5) Cement and cement additives must be compatible with the CO_2 stream and formation fluids (e.g., corrosion-resistant) within the sequestration zone.

(6) Any changes to casing and/or cement materials or designs that deviate from the casing and cementing program in the initial Sequestration Site Certification application must be submitted and approved by the Executive Officer before CCS Project Certification is granted.

(d) Tubing and packer:

(1) Tubing and packer materials used in the construction of each well associated with the CCS project must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards

developed for such materials by API, ASTM International, or comparable standards acceptable to the Executive Officer.

(2) CCS Project Operators of must inject fluids through tubing with a packer set within the long string casing at a point within or below the primary confining layer, or at an interval at a location approved by the Executive Officer.

(3) In determining and specifying the tubing and packer requirements, the CCS Project Operator must consider the following factors:

(A) Depth of setting;

(B) Characteristics of the CO_2 stream (chemical content, corrosiveness, temperature, and density) and formation fluids;

(C) Maximum proposed injection pressure;

(D) Maximum proposed annular pressure;

(E) Proposed injection rate (intermittent or continuous) and volume and/or mass of the CO_2 stream;

(F) Size of tubing and casing; and

(G) Tubing tensile strength, burst, and collapse pressures.

(4) Any change to the tubing and packer used in the well that deviates from those proposed in initial CCS project application for CCS Project Certification must be submitted and approved by the Executive Officer before CCS Project Certification is granted.

(e) Wellheads and Valves:

(1) The CCS Project Operator must equip all wells associated with the CCS project 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 the Executive Officer.

(2) All piping, valves, and facilities must meet or exceed design standards for the maximum anticipated allowable injection pressure, and must be maintained in a safe and leak-free condition.

(3) The CCS Project Operator must equip all ports on the wellhead assembly above the casing bowl of injection wells with valves, blind flanges, or similar equipment.

(4) The CCS Project Operator must equip wells with valves to provide isolation of the wells from the pipeline system and to allow for entry into the wells.

(f) Routine well maintenance:

(1) Routine well maintenance must be conducted at a minimum of every six months. Routine maintenance consists of wellhead valve maintenance and measurement of casing annular pressures. If a significant deviation such that the mechanical integrity of the well is compromised or may become compromised, the appropriate remediation plan must be triggered.

3.2. Pre-Injection Testing

(a) When drilling and constructing wells for a CCS project, the CCS Project Operator must run appropriate logs, surveys, and tests to: (1) determine or confirm the depth, thickness, porosity, permeability, and lithology of the sequestration zone, (2) measure the salinity and TDS of any formation fluids in all relevant geologic formations, (3) ensure conformance with the well construction requirements under subsection C.3.1, and (4) establish accurate baseline data against which future measurements will be compared.

(b) The CCS Project Operator is required to submit a Pre-Injection Testing Plan with the application for Sequestration Site Certification, pursuant to subsection C.1.1.2.

(c) The CCS Project Operator must submit, with the application for CCS Project Certification, a descriptive report that includes an interpretation of the results of such logs and tests. At a minimum, such logs and tests must include:

(1) If pilot holes are drilled as part of the CCS project, the CCS Project Operator must log deviation checks during drilling of all holes constructed by drilling a pilot hole that is enlarged by reaming or another method. Such checks must be at sufficiently frequent intervals 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; and

(2) A series of tests before and upon installation of the surface casing, and before and upon installation of the long string casing:

(A) A series of tests to evaluate the geological and hydrological characteristics of the wellbore following procedures outlined in subsection C.2.3.1; and

(B) Casing inspection logs to evaluate the integrity of the cement bond, such as variable density, temperature, and acoustic logs, or an alternative method approved by the Executive Officer, after the casing is set and cemented.

(3) A series of tests designed to demonstrate the internal and external mechanical integrity of injection wells, which must include:

(A) An annulus pressure test or a radioactive tracer survey, pursuant to subsection C.4.2(b)(1) and C.4.2(b)(3);

(B) A temperature, noise, or oxygen activation log, or a radioactive tracer survey; and

(C) A casing inspection log pursuant to subsection C.*4.3.1.4*.

(4) Any alternative methods that provide equivalent or better information and that are required or approved by the Executive Officer.

(d) The CCS Project Operator must record the fluid temperature, pH, conductivity, and reservoir pressure of the sequestration zone.

(e) At a minimum, the CCS Project Operator must determine or calculate the following information concerning the sequestration zone and confining layer(s) pursuant to subsection C.2.3(a):

(1) Fracture pressure;

(2) Other physical and chemical characteristics of the sequestration zone and confining layer; and

(3) Physical and chemical characteristics of the formation fluids in the sequestration zone.

(f) Upon completion, but prior to operation, the CCS Project Operator must conduct tests to determine hydrogeologic characteristics of the sequestration zone pursuant to subsection C.2.3(a), including a pressure fall-off test and a pump test or injectivity tests.

(g) The CCS Project Operator must provide the Executive Officer with the opportunity to witness all logging and testing conducted in accordance with this section. A state licensed engineer, or equivalent, may be allowed to witness logging and testing, if approved by the Executive Officer.

3.3. Injection Well Operating Requirements

(a) The CCS Project Operator is required to submit a Well Operating Plan with the application for Sequestration Site Certification, pursuant to subsection C.1.1.2. This operating plan must include:

(1) A map showing the injection facilities;

(2) Maximum anticipated surface injection pressure (pump pressure) and daily rate of injection, by well;

(3) 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;

(4) Method of injection; and

(5) Treatment of water injected during water alternating gas (WAG) methods are used for CO_2-EOR purposes;

(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 in the sequestration zone. In no case may injection pressure initiate fractures in the confining system, cause movement of the injection or formation fluids out of the storage complex, or unacceptably increase risk of significant induced seismicity. The CCS Project Operator may propose an alternative injection pressure, provided the operator:

(1) Submits a demonstration as part of the Well Operating Plan that provides an explanation for why injecting below 80 percent of the fracture/parting pressure is not feasible, and why an alternative pressure must be used;

(2) Follows best practices that meet or exceed standards developed for such methods and materials by API, ASTM International, or comparable standards acceptable to the Executive Officer; and

(3) Receives Executive Officer approval of the alternative injection pressure prior to injection.

(c) Injection between the outermost casing and the wellbore is prohibited. The space between the casing and the formation is to be cemented following subsection C.3.1(c)(3).

(d) The CCS Project Operator must fill the annulus between the tubing and the long string casing with a non-corrosive fluid (e.g., a brine containing a corrosion inhibitor).

(e) Other than during periods of well workover approved by the Executive Officer in which the annulus between the tubing and long string casing is disassembled for maintenance or corrective procedures, the CCS Project Operator must monitor

and maintain mechanical integrity in all wells associated with the CCS project at all times.

(f) If an un-remedied shutdown (either downhole or at the surface) is triggered or a loss of mechanical integrity is discovered, the CCS Project Operator must immediately investigate and identify as expeditiously as possible the cause of the shutdown. If, upon such investigation, the well appears to be lacking mechanical integrity, or if monitoring required under subsection C.3.3(e) of this section otherwise indicates that the well may be lacking mechanical integrity, the CCS Project Operator must:

(1) Immediately cease injection in the affected well(s) and in any other wells that may exacerbate the leakage risk of the affected well(s), otherwise, all credits generated are subject to invalidation;

(2) Take all steps reasonably necessary to determine whether there may have been a release of the injected CO_2 stream or formation fluids into any unauthorized zone;

(3) Notify the Executive Officer in writing within 24 hours;

(4) Restore and demonstrate mechanical integrity prior to resuming injection; and

(5) Notify the Executive Officer when injection can be expected to resume.

3.4. Operating Restrictions and Incident Response

(a) In order to receive credit, the CCS Project Operator must cease injection into the affected injection well and must not resume injection into the well without subsequent approval from the Executive Officer if any of the following occurs:

(1) The CCS Project Operator has not performed mechanical integrity testing on the well as required by subsection C.4.2 or the notification and results required under subsection C.4.2.1 have not been provided to the Executive Officer;

(2) The well failed a mechanical integrity test required by subsection C.4.2, or there is any other indication that the well lacks mechanical integrity or is otherwise incapable of performing as approved by the Executive Officer;

(3) An un-remedied automatic alarm or automatic shut-off system is triggered;

(4) The well experiences a significant, unexpected change in pressure in the annulus between the tubing and the long string casing, or injection pressure;

(5) There is any indication of a failure, breach, or hole in the well tubing, packer or well casing, including failures above or below a packer;

(6) There is any indication that fluids being injected into the well are not confined to the intended zone of sequestration;

(7) There is any indication that damage to public health, the environment, natural resources, or loss of hydrocarbons is occurring by reason of the injection; or

(8) Any non-compliance with any certification condition or local regulatory requirement is discovered and the Executive Officer determines that the injection must cease.

(b) The CCS Project Operator must immediately notify the Executive Officer upon ceasing injection operations by reason of subsection C.3.4(a), indicating the affected well and the specific reason for ceasing injection.

(c) The CCS Project Operator must comply with all operational and remedial directives of the Executive Officer related to the reason for ceasing injection.

4. Injection Monitoring Requirements

4.1. Testing and Monitoring

(a) Testing and Monitoring Plan. The CCS Project Operator must prepare, maintain, and comply with a plan for testing and monitoring to ensure that the CCS project is operating as certified and that the CO_2 injected is permanently sequestered. The Testing and Monitoring Plan must be submitted with the application for Sequestration Site Certification, and must include a description of how the CCS Project Operator will meet the testing and monitoring requirements, including accessing sites for all necessary monitoring and testing during the active life of the CCS project and the post-injection site care period. Testing and monitoring associated with CCS projects during the active life of the CCS project must include:

(1) Analysis of the CO_2 stream with sufficient frequency to yield data representative of its chemical and physical characteristics pursuant to subsection C.*4.3.1.1*;

(2) Installation and use, except during well workovers, of continuous recording devices to monitor: (1) injection rate and volume pursuant to subsection C.*4.3.1.2*, (2) injection pressure and the pressure on the annulus between the tubing and the long string casing pursuant to subsection C.*4.3.1.3*, and (3) the annulus fluid volume added;

(3) Corrosion monitoring of well materials, upon well completion and a minimum of once per every five years thereafter, for loss of mass, thickness, cracking, pitting, and other signs of corrosion, to ensure that well components meet the minimum standards for material strength and performance set by API, ASTM International, or equivalent, by:

(A) Analyzing corrosion coupons of the well construction materials placed in contact with the CO_2 stream; or

(B) Routing the CO_2 stream through a loop constructed with the material used in the well and inspecting materials in the loop;

(C) Performing casing inspection logs; or

(D) Using an alternative method approved by the Executive Officer.

(4) Periodic monitoring of pressure and/or composition above the storage complex. In sites where it is feasible and useful, groundwater quality and geochemistry must be considered. The rationale and leakage detection threshold of the selected monitoring method must be demonstrated;

(5) The location and number of monitoring wells based on specific information about the CCS project, including injection rate and volume, geology, the presence of artificial penetrations and other factors;

(6) The monitoring frequency and spatial distribution of monitoring wells based on any modeling results required by subsection C.2.4.1;

(7) A demonstration of external mechanical integrity pursuant to subsection C.4.2 at least once per year, or on a schedule approved by the Executive Officer, but not to exceed once every five years, until the injection well is plugged, and, if required by the Executive Officer, a casing inspection log pursuant to requirements at subsection C.4.2(c) at a frequency established in the Testing and Monitoring Plan;

(8) A pressure fall-off test pursuant to subsection C.*4.3.1.5*;

(9) A demonstration of the suitability of the testing and monitoring plan to provide data sufficient to validate the computational model, as required by subsection C.2.4, and to 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. The demonstration must include plans for testing and monitoring to:

(A) Track the extent of the CO_2 plume, and the presence or absence of elevated pressure. Monitoring data must be used to:

1. Assess the three-dimensional extent of the CO_2 plume, and to determine if it is contained within the sequestration zone and storage complex;

2. Update and test the computational model; and

3. Determine if the modeled CO_2 plume migration will remain within the storage complex until at least the end of the post-injection site care and monitoring period, pursuant to subsections C.2.4.2 and C.2.4.4.

(B) The demonstration must include an inventory of the testing and monitoring methods, and a description of the suitability of the methods to provide site-specific, risk-based data.

(10) A demonstration of how the monitoring plan and methods will be designed to detect and quantify any CO_2 leakage. The demonstration must include plans for testing and monitoring that:

(A) Specifies the process and detection threshold at which leakage from any potential pathway, from reservoir to surface, will be detected and quantified;

(B) Uses maps and computational modeling to show how measurements and computational models will be used to trigger a finding of leakage; and

(C) Describes how monitoring data will be used to (1) determine and quantify any CO_2 leakage, and (2) show that mitigation attempts have been effective.

(11) Surface monitoring to detect potential shallow subsurface or atmospheric CO_2 leakage;

(12) A description of the methods, and estimate of precision and accuracy of the methods used to measure and quantify CO_2 leakage from the storage complex (MT CO_2/year), as required by subsection B.2.2(e) Equation 6.

(13) At a minimum, the Testing and Monitoring Plan must stipulate and include:

(A) The frequency of data acquisition;

(B) A record keeping plan;

(C) The frequency of instrument calibration activities;

(D) The QA/QC provisions on data acquisition, management, and record keeping that ensures it is carried out consistently and with precision;

(E) The role of individuals performing each specific monitoring activity; and

(F) Methods to measure and quantify the following data:

1. Quantity of CO_2 emitted from the capture site;

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

3. Quantity of CO_2 injected into each well in the CCS project metered at a location approved by the Executive Officer, that accounts for complicating factors, such as the individual flows that may occur at wellheads or pressure and temperature variations, and that provides sufficiently accurate data.

(14) Any additional monitoring, as required by the Executive Officer, necessary to support, upgrade, and improve computational modeling of the CO_2 plume extent required under subsection C.2.4.1;

(15) The CCS Project Operator must periodically review the Testing and Monitoring Plan to incorporate monitoring data collected under this subsection, operational data collected under subsection C.3, and the most recent CO_2 plume extent reevaluation performed under subsection C.2.4.4; and

(16) The CCS Project Operator must review the Testing and Monitoring Plan no less than once every five years. Based on this review, the CCS Project Operator must submit an amended Testing and Monitoring Plan or demonstrate to the Executive Officer that no amendment to the Testing and Monitoring Plan is needed. Any amendments to the Testing and Monitoring Plan must be approved by the Executive Officer. Amended plans or demonstrations must be submitted to the Executive Officer as follows:

(A) Within one year of a CO_2 plume extent reevaluation; or

(B) When required by the Executive Officer.

4.2. Mechanical Integrity Testing

(a) Any well that is part of a CCS project must have and maintain mechanical integrity at all times during operation, other than during periods of well workover for maintenance or corrective action. A well has mechanical integrity if:

(1) There is no internal leak in the casing, tubing, or packer;

(2) There is no significant external fluid movement out of the sequestration zone through channels adjacent to the wellbore; and

(3) Corrosion monitoring, pursuant to subsection C.*4.3.1.4*, reveals no loss of mass or thickness that may indicate the deterioration of well components (casing, tubing, or packer).

(b) The CCS Project Operator must conduct mechanical integrity testing as follows:

(1) Internal mechanical integrity must be demonstrated prior to commencing injection operations. Thereafter, the internal mechanical integrity of each well must be tested at least once every five years, after every workover (see subsection C.4.2(c)(6), below), or at the request of the Executive Officer. CCS Project Operator must submit a descriptive report of the internal mechanical integrity test results with the application for CCS Project Certification.

(2) External mechanical integrity must be demonstrated within three months after injection has commenced. Thereafter, wells must be tested at least once each year, or on a testing schedule approved by the Executive Officer.

(3) The CCS Project Operator must demonstrate internal mechanical integrity and test for possible leaks in the casing, tubing, or packer, under subsection C.4.2(b)(1), via:

(A) An annulus pressure test;

(B) A radioactive tracer survey; or

(C) An alternative test approved by the Executive Officer.

(4) The CCS Project Operator must demonstrate external mechanical integrity and test for possible leaks from channels adjacent to the wellbore under subsection C.4.2(b)(2), via:

(A) A temperature log;

(B) A noise log;

(C) An oxygen activation log;

(D) A radioactive tracer survey; or

(E) An alternative test approved by the Executive Officer.

(5) The well must pass a suitable annulus pressure test to demonstrate mechanical integrity after any workover that has the potential to compromise the internal mechanical integrity of the well, including but not limited to the downhole replacement of tubing, safety valves, and/or electrical submersible pumps.

(6) The CCS Project Operator must demonstrate external mechanical integrity prior to plugging the well following the requirements of this subsection and subsection C.5.1.

(c) Following the initial annulus pressure test, the CCS Project Operator must continuously monitor pressure on the annulus between the tubing and long string casing, except during well workovers. Continuous monitoring of the pressure on the annulus must be used to confirm internal mechanical integrity during the injection phase of the project, and must be performed in concert with continuous monitoring of injection pressure, rate, and annulus fluid volume pursuant to subsections C.4.3.1.1, C.4.3.1.2, and C.4.3.1.3.

(d) In conducting and evaluating the tests listed in this section or others to be allowed by the Executive Officer, the CCS Project Operator must apply methods and standards generally accepted in the industry. When the CCS Project Operator reports the results of mechanical integrity tests to the Executive Officer, he/she must include a description of the tests and a justification for the methods used.

(e) Prior notice and reporting.

(1) The CCS Project Operator must notify the Executive Officer of his or her intent to demonstrate mechanical integrity at least 30 days prior to such demonstration. At the discretion of the Executive Officer, a shorter time period may be allowed.

(2) Reports of mechanical integrity demonstrations that include logs must include an interpretation of results by an experienced log analyst. The CCS Project Operator must report the results of a mechanical integrity demonstration within the time period specified in subsection C.1.1.3.

(f) Gauge and meter calibration: The CCS Project Operator must calibrate all gauges used in mechanical integrity demonstrations and other required monitoring to an accuracy of not less than five percent of full scale, within one year prior to each required test.[8] The date of the most recent calibration must be noted on or near the gauge or meter. A copy of the calibration certificate must be submitted to the Executive Officer with the report of the test. Pressure gauge resolution must be no greater than five psi. Certain mechanical integrity and

[8] With the exception of any permanent downhole gauges that cannot be calibrated at the surface.

other testing may require greater accuracy and must be identified in the procedure submitted to the Executive Officer prior to the test.

4.2.1. Reporting of Mechanical Integrity Tests

(a) The CCS Project Operator must submit a descriptive report prepared by an experienced log analyst that includes the results of any mechanical integrity test with the application for CCS Project Certification, and annually, thereafter through the active life of the CCS Project. At a minimum, the report must include:

(1) Chart and tabular results of each log or test;

(2) The interpretation of log results provided by the log analyst;

(3) A description of all tests and methods used;

(4) The records and schematics of all instrumentation used for the tests and the most recent calibration of any instrumentation;

(5) The identification of any loss of mechanical integrity, evidence of fluid leakage, and remedial action taken;

(6) The date and time of each test;

(7) The name of the logging company and log analyst;

(8) For any tests conducted during injection, operating conditions during measurement, including injection rate, pressure, and temperature (for tests run during well shut-in, this information must be provided relevant to the period prior to shut-in); and

(9) For any tests conducted during shut-in, the date and time of the completion of injection and records of well pressure re-equilibration.

4.2.2. Loss of Mechanical Integrity

(a) If the CCS Project Operator or the Executive Officer finds that a well (1) fails to demonstrate mechanical integrity during a test, (2) fails to maintain mechanical integrity during operation, or (3) that a loss of mechanical integrity is suspected during operation, the CCS Project Operator must:

(1) Take all steps reasonably necessary to determine whether there may have been a release of the injected CO_2 stream or formation fluids into any unauthorized zone. If there is evidence of substantial endangerment to public health or the environment from any fluid movement out of the intended

storage complex, implement the Emergency and Remedial Response Plan, as described in subsection C.6;

(2) Follow the reporting requirements as directed in subsection C.1.1.3; and

(3) Restore and demonstrate mechanical integrity prior to resuming injection or plugging the well.

(b) If the well loses mechanical integrity prior to the next scheduled test date, then the well must be repaired and retested within 30 days of losing mechanical integrity.

(c) If the well lost mechanical integrity prior to the next scheduled test date, and it was repaired, the CCS Project Operator must submit a descriptive report documenting the type of failure, the cause, the required repairs, and a new test of mechanical integrity following the requirements of subsection C.4.2 in the next quarterly report.

4.3. CCS Project Monitoring

(a) Monitoring requirements for CCS projects are addressed in two separate categories: CCS project emissions monitoring, and the monitoring, measurement, and verification of containment. The first includes quantification and measurement activities required to quantify the net GHG reductions from the CCS project. The second category is for monitoring, measurement, and verification activities that are required to ensure that the CO_2 injected is permanently contained with the storage complex.

(b) The CCS Project Operator must install and use:

(1) Continuous recording devices to monitor: the injection pressure, the rate, volume and/or mass, and temperature of the CO_2 stream, and the pressure on the annulus between the tubing and the long string casing and annulus fluid volume; and

(2) Alarms and automatic surface shut-off systems (e.g., automatic shut-off, check valves) for wells, or other mechanical devices that provide equivalent protection.

(c) The CCS Project Operator must retain all records and all monitoring information, including all calibration and maintenance records and all original chart recordings for continuous monitoring instrumentation and copies of all reports, for emissions and containment monitoring for a period of 10 years after site closure.

4.3.1. CCS Project Emissions Monitoring

(a) Emissions monitoring requirements include measurements of relevant parameters to account for all supplemental energy inputs (e.g., fossil fuels and electricity) required for the operation of the CCS project. Data capture must be sufficient to ensure that the quantification and documentation of CO_2 sequestered is replicable and verifiable pursuant to the Accounting Requirements in section B.

(b) CCS project monitoring techniques must use calibrated metering equipment such as fluid flow meters, utility meters (gas and electricity), and fluid chemistry analyzers. Meters must be maintained to operate consistent with design specifications and must be calibrated on a regular basis.

(c) Data quality management must include sufficient data capture to support quantification and verification of CO_2 sequestered. Any assumptions and contingency procedures must be documented. Any monitoring plan and implementation must take into account the location, type of equipment, and frequency by which each variable is measured.

4.3.1.1. Analysis of the CO_2 Stream

(a) The CCS Project Operator must sample and analyze the CO_2 stream at a frequency sufficient to yield data representative of the chemical and physical characteristics of the injectate (i.e., at least once every quarter), whenever the result may deviate from the original certified specifications, and as requested by the Executive Officer.

(b) Analysis of the CO_2 stream must be reported quarterly, pursuant to subsection C.1.1.3. The report must include characteristics such as fluid composition (i.e., fraction of CO_2 and other constituents measured on a volumetric or mass basis at a known temperature and pressure), temperature, pressure, and any other parameters needed to identify potential interactions between the injectate and the formation or well materials. The CCS Project Operator must justify that the samples are representative of the fluid streams and suitable for use in accounting and fluid-flow modeling. The CCS Project Operator must submit, at a minimum, the following:

(1) A list of chemicals analyzed, including CO_2 and other constituents (e.g., sulfur dioxide, hydrogen sulfide, nitrogen oxides);

(2) A description of the sampling methodology, noting any differences from those listed in the Testing and Monitoring Plan and an explanation of why a different method was used;

(3) Any laboratory analytical methods used, the name of the laboratory performing the analysis, and official laboratory analytical reports including sample chain-of-custody forms;

(4) All sample dates and times;

(5) A tabulation of all available carbon dioxide stream analyses, including QA/QC samples;

(6) Interpretation of the results with respect to regulatory requirements and past results;

(7) Identification and explanation of data gaps, if any; and

(8) Any identified necessary changes to the CCS project Testing and Monitoring Plan.

(c) The report must include a determination that any potential chemical reactions between the injectate and the formation or well materials are minimal and will not significantly affect the integrity of the well or the injectivity of the formation.

(d) The report must include a determination that no component of the injectate meets the qualifications of hazardous waste under the RCRA, 42 U.S.C. 6901 *et seq.* (1976), and/or CERCLA, 42 U.S.C. 9601 *et seq.* (1980).

(e) Injectate fluid samples must be collected from a point such that the sample is representative of the composition of the injectate. CCS Project Operators must provide a demonstration of the suitability of the sample point, along with any calculations required for complex systems (e.g., CO_2-EOR operations with more than one source of CO_2).

4.3.1.2. Continuous Monitoring of Injection Rate and Volume

(a) The CCS Project Operator must continuously monitor the injection rate and volume for each CCS injection well.

(b) Flow rate data must be used (1) to determine the cumulative volume of CO_2 injected, and (2) to confirm compliance with the operational conditions of the Permanence Certification.

(c) Monitoring requirements must include measurements of relevant parameters to account for the flow rate of injected fluids, the concentration of the fluid stream, and the energy inputs required for operation.

(d) CCS Project Operators are required to perform the following measurements and monitoring for injected fluids:

(1) Flow rate of injection stream:

(A) Continuous measurement of the fluid flow rate, composition, and density, where continuous measurement is defined as a minimum of one measurement every 15 minutes;

(B) Meter readings need to be temperature and pressure compensated such that the meter output is set to standard reference temperatures and pressures;

(C) Flow meters must be located such that accurate measurements can be collected for accounting purposes. Where possible, flow meters should be placed immediately upstream of the gas injection process, such that they are downstream of all capture, compression, and transport to account for any fugitive losses or venting. CCS Project Operators must justify their meter placement in the Testing and Monitoring Plan pursuant to subsection C.4.1. Flow meters must be placed based on manufacturer recommendations;

(D) Flow meters must be calibrated according to manufacturer specifications. Meters must be checked/calibrated at regular intervals according to these specifications and industry standards; and

(E) Ownership transfer must be clearly documented for CO_2 transferred (third-party injection activity).

(2) Concentration of injection stream:

(A) Continuous measurement of the fluid composition and density where continuous measurement is defined as a minimum of one measurement every 15 minutes; and

(B) The fluid composition must be metered downstream of the capture and processing equipment, and volume measured upstream, prior to any mixing of new and recycled CO_2.

(e) Injection rate and volume data must be submitted in the quarterly reports pursuant to subsection C.1.1.3. The report must include, at a minimum:

(1) Tabular data of all flow rate measurements and a description of interpretation of the data aided with charts or graphs;

(2) A description of the measuring methodology and technology, noting any differences from those given in the Testing and Monitoring Plan and an explanation of why a different methodology was used;

(3) The monthly average flow rate;

(4) The monthly maximum and minimum values;

(5) The total volume (mass) injected each month;

(6) The cumulative volume (mass) calculated for the CCS project;

(7) If flow rate exceeded certified operational limits during the reporting period, an explanation of the event(s), including the cause of the excursion, the length of the excursion, and response to the excursion;

(8) Identification and explanation of data gaps, if any; and

(9) Any identified necessary changes to the CCS project Testing and Monitoring Plan and the justification for those changes.

4.3.1.3. Continuous Monitoring of Injection Pressure

(a) During operation, the CCS Project Operator must continuously monitor injection pressure, at the wellhead (i.e., wellhead pressure) and downhole (i.e., bottom-hole pressure).

(b) Injection pressure is monitored to ensure that the fracture pressure of the sequestration zone and the burst pressure of the well tubing are not exceeded and that the owner or CCS Project Operator is in compliance with certified operating conditions.

(c) The CCS Project Operator must ensure that the injection pressure remains at or below 80 percent of the fracture pressure of the sequestration zone, or below the Executive Officer-approved injection pressure pursuant to subsection C.3.3(b).

(d) During injection, pressure in the annular space directly above the packer must be maintained at a pressure higher[9] than the tubing pressure.

(e) Maximum allowable surface pressure must equal top perforation or completion depth, in true vertical depth, multiplied by the difference between the injection gradient and the injectate fluid gradient.

(f) Significant changes of the pressure in the annulus between the tubing and the long string casing during injection may indicate a loss of internal mechanical integrity. If pressure monitoring indicates that the well is experiencing a loss of mechanical integrity, the CCS Project Operator must follow the procedures outlined in subsection C.4.2.2.

[9] U.S. EPA Region 8, Groundwater Section Guidance Number 39, (1995; updated 2006), Denver, CO.

(g) Pressure data must be reported in the annual reports following subsection C.1.1.3. The CCS Project Operator must submit, at a minimum, the following:

(1) Tabular data of all pressure measurements, a description and interpretation of the data aided with charts or graphs, and gauge calibration records;

(2) A description of the measurement methodology, noting any differences from what was established in the Testing and Monitoring Plan, and a justification of why a different methodology was used;

(3) Corrections made due to the impacts of fluctuating injectate temperature;

(4) The monthly average value for injection pressure;

(5) The monthly maximum and minimum values for injection pressure;

(6) If pressure exceeded permit limits during the reporting period, an explanation of the event(s), including the cause of the exceedance, the length of the excursion, and response to the excursion;

(7) Identification and explanation of data gaps, if any; and

(8) Any identified necessary changes to the CCS project Testing and Monitoring Plan to ensure continued protection of public health and the environment, including any changes in the data measurement or averaging methods.

4.3.1.4. Corrosion Monitoring and Casing Inspection

(a) CCS Project Operators must monitor well materials for corrosion at a frequency specified in the Testing and Monitoring Plan following subsection C.4.1, not to exceed once every five years.

(b) Well components must be monitored for corrosion using at least one of the following methods:

a. Corrosion coupons or loops;

b. Casing inspection logs (CILs), such as caliper, electromagnetic phase-shift, electromagnetic flux test log, or ultrasonic test logs; or

c. An alternative method approved by the Executive Officer.

(c) Well corrosion monitoring data must be reported annually to CARB including, including at a minimum, the following:

(1) A description of the techniques used for corrosion monitoring;

(2) Measurement of (mass and thickness/weight) loss from any corrosion coupons or loops used;

(3) Assessment of additional corrosion, including pitting, in any corrosion coupons or loops;

(4) Measurement of thickness loss or corrosion detected in any CILs;

(5) All measured CILs and comparison to previous logs;

(6) Identification and explanation of data gaps, if any; and

(7) Any identified necessary changes to the CCS project Testing and Monitoring Plan.

4.3.1.5. Pressure Fall-Off Testing

(a) CCS Project Operators must perform a pressure fall-off test of each well at least once every five years pursuant to subsection C.4.1. The CCS Project Operator may propose an alternative test method and/or schedule, provided the operator:

(1) Submits a demonstration as part of the Testing and Monitoring Plan that:

i. Describes the proposed alternative method of testing; and

ii. Provides an explanation for why fall-off tests are inappropriate and how the proposed alternative method will provide data equivalent data fall-off tests.

(2) Follows best practices that meet or exceed standards developed for such methods and materials by API, ASTM International, or comparable standards acceptable to the Executive Officer; and

(3) Receives Executive Officer approval of the alternative test method and/or schedule prior to operation.

(b) Upon shutting-in the well, pressure measurements must be taken continuously for a period of time, and pressure decay at the well must be monitored;

(c) The CCS Project Operator must use temperature and bottom-hole pressure measurements, although surface pressure at the wellbore may suffice, if positive pressure is maintained throughout the test; and

(d) The results of pressure fall-off tests must be reported to the Executive Officer within 30 days following the test and summarized with the annual reporting requirements pursuant to subsection C.1.1.3. Reports must include, at a minimum:

(1) The location and name of the test well and the date/time of the shut-in period;

(2) Depths of recorded bottom-hole pressure and temperature;

(3) Records of gauges;

(4) Raw data collected during the fall-off test in a tabular format, if required by the Executive Officer;

(5) Measured injection rates and pressure from the test well and any off-set wells in the same zone, including data from before shut-in;

(6) Information on pressure gauges used (e.g., manufacturer, accuracy, depth deployed) and demonstration of gauge calibration according to manufacturer specifications;

(7) Diagnostic curves of test results, noting any flow regimes;

(8) Description of quantitative analysis of pressure-test results, including use of any commercial software, and any considerations of multi-phase effects;

(9) Calculated parameter values from analysis, including transmissivity, permeability, and skin factor;

(10) Analysis and comparison of calculated parameter values to previously measured values (using any previous methods) and to values used in computational modeling and storage complex delineation;

(11) Identification of data gaps, if any; and

(12) Any identified necessary changes to the CCS project Testing and Monitoring Plan.

4.3.1.6. Monitoring of Wellheads and Valves

(a) The CCS Project Operator must prepare, maintain, and comply with an Inspection and Leak Detection Plan for all surface equipment, including wellheads, valves, and pipelines. This Inspection and Leak Detection Plan must be approved by the Executive Officer;

(b) The Inspection and Leak Detection Plan must include, at a minimum, procedures that the CCS Project Operator will follow that include:

(1) Quarterly inspection of all wellheads, valves, and piping, employing effective gas leak detection technology;

(2) Bi-annual testing of all surface and subsurface safety valve systems to ensure ability to hold anticipated pressure; and

(3) 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.

(c) The plan must include inspection of the wellhead assembly and attached pipelines for each of the injection wells used in association with the CCS project, as well as the surrounding area within a 100-foot radius of the wellhead of each of the wells;

(d) The CCS Project Operator must select and use gas leak detection technology that 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;

(e) Upon finding that a surface or subsurface safety valve is inoperable, the CCS Project Operator must immediately shut-in the well and repair the valve within 90 days. An appropriate alternative timeframe for testing a valve or addressing an inoperable surface or subsurface safety valve may be approved by the Executive Officer;

(f) Documentation of all inspections, tests, and results must be maintained by the CCS Project Operator and available for CARB review during the active life of the CCS project; and

(g) Testing of surface equipment operational integrity must be conducted in accordance with API Recommended Practice 14B[10], or equivalent.

4.3.2. Monitoring, Measurement, and Verification of Containment

(a) Every CCS project must undertake monitoring activities to ensure safe and permanent storage of CO_2 in accordance with the Permanence Certification.

(b) The Monitoring, Measurement, and Verification Plan must be linked to the risk assessment (pursuant to subsection C.2.2), and must be used as an effective part of the risk management strategy for the CCS project.

[10] API Recommended Practice 14B, "Design, Installation, Operation, Test, and Redress of Subsurface Safety Valve Systems," 6 (2005): 37 p.

(c) The Monitoring, Measurement, and Verification Plan must be specific to the CCS project's storage complex, including a demonstration that the methods selected are sensitive to the CO_2 plume within the geologic environment of the storage reservoir. At a minimum, the Monitoring, Measurement, and Verification Plan must meet the requirements of section 95491.1(c) of the LCFS Regulation and include GHG reductions as well as containment. The plan must be able to;

(1) Validate that the computational modeling shows the CO_2 plume will remain within the storage complex at least until the end of the post-injection site care and monitoring period; and

(2) Ensure that if any CO_2 leakage occurs, it is detected with a detection threshold equal to, or better than, 5% the total volume of leaked CO_2.

(d) The Monitoring, Measurement, and Verification Plan must be submitted as part of the Testing and Monitoring Plan with the application for Sequestration Site Certification. The plan must include the methods the CCS Project Operator will use to monitor the extent of the CO_2 plume and elevated pressure, any atmospheric CO_2 leakage, and natural and induced seismic activity.

(e) The Monitoring, Measurement, and Verification Plan must include methods and plans for the quantification of CO_2 leakage if it occurs, including an estimate of the accuracy and precision of those methods and plans, which will be used to inform GHG emission reduction credit invalidation.

(f) The Executive Officer may require the CCS Project Operator to perform additional monitoring, as necessary, to support, upgrade, and improve computational modeling of the storage complex and to determine compliance with Permanence Certification.

4.3.2.1. Plume and Elevated Pressure- Tracking

(a) CCS Project Operators must track the extent of the free-phase CO_2 plume, and the pressure development within the storage complex by using:

(1) Well-based methods within the storage complex; and

(2) Indirect methods such as seismic, gravity, or electromagnetic surveys and CO_2 detection tools.

(b) The Monitoring, Measurement, and Verification Plan and schedule must be designed to:

(1) Monitor the free-phase CO_2 plume location, thickness, and saturation;

(2) Track the pressure development within the storage complex over time;

(3) Validate computational modeling results; and

(4) Demonstrate that operations are not leading to elevated CO_2 or brine leakage or seismic risks.

(c) Monitoring free-phase CO_2 plume development: CCS Project Operators must monitor the free-phase CO_2 plume extent, and must consider the following methods to detect the shape of CO_2 saturation of the pore space in the sequestration zone:

(1) Time-lapse three-dimensional surface seismic surveys;

(2) Downhole, time-lapse three-dimensional vertical seismic profiling surveys;

(3) Wireline-based saturation, sonic, and gravity logging;

(4) Electrical resistivity tomography (surface or downhole); and

(5) An alternative test approved by the Executive Officer.

(d) Monitoring pressure development: CCS Project Operators must monitor the elevated pressure of the CO_2 plume. The CCS Project Operator must consider the following methods and provide an estimate of the site-specific quality of detection for each chosen method:

(1) Satellite based synthetic aperture radar (InSAR) monitoring (satellite-based);

(2) Pressure gauges (downhole);

(3) Tilt meters or inclinometers (surface and well-based); and

(4) Alternative methods approved by the Executive Officer.

(e) Plume and elevated pressure-tracking data must be reported quarterly (subsection C.1.1.3) for methods in which data are collected continuously or monthly, and annually for methods in which data are collected yearly (or longer), based on the monitoring timeline pursuant to subsection *C.4.3.2.1*(b). Reports must include, at a minimum:

(1) Tabular data of all measurements and a description and interpretation of the data aided with charts, graphs, and maps of the three-dimensional extent of the CO_2 plume;

(2) A description of the measurement methodology, noting any differences from what was established in the Testing and Monitoring Plan, and a justification of why a different methodology was used;

(3) An assessment of any deviations from the modeled three-dimensional extent of the CO_2 plume, if observed, and the determination of whether or not the results trigger corrective action pursuant to subsection C.2.4.3;

(4) The monitoring approach and equipment should periodically be reevaluated to determine if (1) the methods are useful and produce accurate data, and (2) if improved methods are available; and

(5) Any identified necessary changes to the CCS project Testing and Monitoring Plan and the justification for those changes.

4.3.2.2. Surface and Near-Surface Monitoring

(a) The CCS Project Operator must monitor the surface and near-surface of a CCS project to detect potential atmospheric CO_2 leakage.

(b) The CCS Project Operator must design surface and near-surface monitoring based on potential risks to atmospheric CO_2 leakage within the surface projection of the storage complex.

(c) The monitoring frequency and spatial distribution of surface and near-surface monitoring must be decided by analysis of baseline data pursuant to subsection C.2.5. Methods must be able to distinguish between leakage signals and other variations, such as land use, climate, and ecosystems changes. Methods must be able to (1) attribute the source of leakage, (2) potentially manage or reduce future leakage, and (3) quantify the losses, including any CO_2 leakage.

(d) Surface monitoring of point sources: CCS Project Operators must monitor and quantify CO_2 or other gases associated with the storage complex (e.g. CH_4, in the case of injection into a hydrocarbon reservoir) in the atmosphere in order to detect potential releases from wellbores, faults, and other migration pathways. Broad aerial monitoring should focus on the footprint of the free-phase CO_2 plume, while more targeted monitoring can occur at wells and pipelines. CCS Project Operators must use both intermittent and continuous monitoring methods, must use one or more of the following tools to detect atmospheric CO_2 leakage:

(1) Optical sensors;

(2) Infrared (IR) open-path detectors;

(3) Forward looking infrared (FLIR) cameras;

(4) Multi-spectral imaging;

(5) Atmospheric tracers, including natural and injected chemical compounds;

(6) Eddy covariance flux measurement techniques; and

(7) Alternative methods approved by the Executive Officer.

(e) Monitoring of all wellbores: The CCS Operator must monitor all wells that intersect the storage complex at depth. Monitoring should include direct observation of the wells, if possible, and surface air monitoring around the wellbore. Monitoring should focus on identifying CO_2 flux in the vicinity of the wellbore that may indicate a catastrophic leak.

(f) Ecosystem stress monitoring: CCS Project Operators must conduct annual vegetation surveys to measure potential vegetative stress resulting from elevated CO_2 in soil. CCS Project Operators must consider methods such as satellite imagery, aerial photography, and spectral imagery. Any indications of anomalous change from remote sensing must be subject to ground-based verification and, if necessary, soil gases must be analyzed to determine the presence or absence of sequestration zone brine or characteristics of injected CO_2, including any introduced tracers.

(g) If deep subsurface or atmospheric monitoring suggests that atmospheric CO_2 leakage may occur or has occurred, the CCS Project Operator must perform continuous and intermittent geochemical monitoring of the soil and vadose zone, including sampling of CO_2, ratios of CO_2 to other gasses, natural chemical tracers, and introduced tracers, in order to detect potential releases from wellbores, faults, and other migration pathways, and separate ecosystem variability from leakage signal. CCS Project Operators must use one or more of the following methods:

(1) Flux accumulation chamber methods;

(2) Active sample collection methods including shallow monitoring wells, ground probes and permanent soil gas probes;

(3) Passive sample collection methods; and

(4) Alternative methods approved by the Executive Officer.

(h) If deep subsurface or atmospheric monitoring suggests that atmospheric CO_2 leakage may occur or has occurred, CCS Project Operators must consider using near-surface electrical conductivity surveys to measure variations in soil salinity

to determine the presence or absence of brine from potential brine leakage from the sequestration zone.

(i) Surface and near-surface monitoring data must be reported and interpreted annually. Reports must include, at a minimum:

(1) Tabular data of all measurements and a description and interpretation of the data aided with charts, graphs, and maps of sample collection locations;

(2) A description of the measurement methodology, noting any differences from what was established in the Testing and Monitoring Plan, and a justification of why a different methodology was used;

(3) If leakage is detected, it must be attributed, quantified, and assessed for potential corrective action, and CCS Project Operators must appropriately manage, stop, and mitigate leakage;

(4) Any identified necessary changes to the CCS project Testing and Monitoring Plan and the justification for those changes; and

(5) If data indicate a surface leak of CO_2 from the storage complex, the CCS Project Operator must perform all actions necessary to identify and remediate the leak following the Emergency and Remedial Action Plan in subsection C.6.

4.3.2.3. Seismicity Monitoring

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

(1) The design of the array should consider the seismic risk. Location of small events can be helpful in risk reduction, but sufficient planning is needed to collect and analyze the data. Analysis of the microseismicity must consider if the risk of triggering an earthquake of Richter magnitude 2.7,[11] or greater, is significantly increased by injection. If an increase in risk is detected and determined, mitigation of the risk is required; and

(2) The array should be calibrated with check-shots, preferably at depth.

[11] Updated Underground Injection Control Regulations Pre-Rulemaking Discussion Draft, 04-26-17, Division of Oil, Gas, and Geothermal Resources. Available at http://www.conservation.ca.gov/dog/general_information/Pages/UICupdate.aspx

(b) From commencement of injection activity to its completion, the CCS Project Operator must continuously monitor for indication of an earthquake of magnitude 2.7 or greater occurring within a radius of one mile of injection operations.

(1) A CCS Project Operator in California must continuously monitor the California Integrated Seismic Network, or other equivalent jurisdictional network; or

(2) For CCS projects located out of California, the CCS Project Operator must continuously monitor the U.S. Geological Survey's National Earthquake Information Center and Advanced National Seismic System, or equivalent.

(c) If an earthquake of magnitude 2.7 or greater is identified under subsection C.*4.3.2.3*(b), the following requirements apply:

(1) The CCS Project Operator must immediately notify the Executive Officer when and where (i.e., the epicenter and hypocenter) the earthquake occurred;

(2) CARB, in consultation with the CCS Project Operator and the California Geological Survey, or local geological survey or equivalent, will conduct an evaluation of the following:

(A) Whether there is indication of a causal connection between the injection activity and the earthquake;

(B) Whether there is a pattern of seismic activity in the area that correlates with nearby injection activity; and

(C) Whether the mechanical integrity of any well, facility, or pipeline within the radius specified in subsection C.*4.3.2.3*(b) has been compromised.

(d) If the CCS Project Operator obtains evidence that an earthquake has caused a failure of the mechanical integrity of wells, facilities, or pipelines, which may cause potential CO_2 emissions to the atmosphere, the CCS Project Operator must implement the Emergency Remedial Response Plan pursuant to subsection C.6.

(e) The preliminary results of the seismic evaluation must be reported to the Executive Officer within 30 days following the earthquake, with a final report submitted within 120 days. The report must include, at a minimum:

(1) The date, time, and magnitude of the earthquake;

(2) The location and distance of the epicenter from the CCS project;

~~(3) The results of the investigation into the link between the injection activity and the earthquake or pattern of seismicity;~~

~~(4) Any emergency and remedial actions taken pursuant to subsection C.6;~~

~~(5) A description of any investigations and tests conducted to assess the mechanical integrity of wells and other surface equipment, and a demonstration that the well and equipment were either not damaged by the earthquake or that mechanical integrity was restored prior to the re-initiation of injection; and~~

~~(6) Any identified changes necessary to the CCS project Testing and Monitoring Plan.~~

~~*4.3.2.4.*~~**4.3. Verification**

(a) CCS projects must be verified pursuant to sections 95500 through 95503 of the LCFS Regulation, and the requirements of the ~~CCS protocol~~GCS Protocol.

(b) Each verification team must include:

(1) A CARB-accredited oil and gas systems specialist pursuant to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions section 95131(a); and

(2) A professional geologist licensed under Chapter 12.5 of Division 3 of the California Business and Professions Code §§ 7800 – 7887, or equivalent professional geologist approved by ~~the Executive Officer.~~ CARB. An explanation demonstrating that the verification team includes a professional geologist with the required experience and expertise must be included in the Notice of Verification Services.

(3) The required experience and expertise may be demonstrated by a single individual, or by a combination of individuals.

(4) The verification team must be the same verification team used to certify permanence pursuant to the GCS Protocol.

(c) Verification must include a review of the following:

(1) Documentation and maps to verify the boundaries of the project, including the location of monitoring and measurement equipment, ~~and~~ procedures for data quality assurance and quality control, and monitoring plan; and

(2) ~~The operator's CCS project's risk rating for determining its~~The determination of the projects contribution to the LCFS Buffer Account ~~as calculated under Appendix G~~.

(3) ~~All plans, assessments, and reports for conformance~~ Conformance with the LCFS Regulation, Greenhouse Gas Quantification Methodology for Carbon Capture and Sequestration under the LCFS, and the requirements of ~~this protocol~~GCS Protocol.

~~(d) Verification of CO_2 leakage.~~

~~(1) Within six months of an event that triggers CO_2 leakage, the operator must submit the verified mass of CO_2 leakage as calculated under section C.2.4.4(d). The verification team must review the quantification and methods for determining CO_2 leakage reported by the project operator under section C.2.4.4(d). To verify the mass of CO_2 leakage a full verification must be conducted pursuant to sections 95500 through 95503, including a site visit. The verified mass of CO_2 leakage may be submitted as a separate verification service, or incorporated into a chapter of the detailed verification report submitted pursuant to section 95501(c)(3)(A), if the timing of the verification coincides with annual verification being conducted for the CCS project.~~

~~5. Well Plugging and Abandonment and Post-Injection Site Care and Site Closure~~

~~5.1. Well Plugging and Abandonment~~

~~(a) Well Plugging and Abandonment Plan: The CCS Project Operator must prepare, maintain, and comply with a plan to plug all injection, production, and monitoring wells associated with the CCS project that is acceptable to the Executive Officer.~~

~~(b) The CCS Project Operator must demonstrate in the plan that each well will be plugged in a manner that prevents the well from serving as a conduit for fluid or CO_2 leakage out of the storage complex.~~

~~(c) The Well Plugging and Abandonment Plan must be submitted as part of the application for Sequestration Site Certification, and the plan must be updated as needed throughout the life of the CCS project.~~

~~(d) The Well Plugging and Abandonment Plan must include the following information:~~

~~(1) Appropriate tests or measures for determining bottom-hole pressure. Bottom-hole pressure must be used to determine the appropriate density of plugging fluids to achieve static equilibrium prior to plug placement;~~

(2) Appropriate testing methods to ensure external mechanical integrity as specified in subsection C.4.2. External mechanical integrity testing is required to ensure that the long-string casing and cement left in the ground after the well is plugged will maintain their integrity over time;

(3) The type and number of plugs to be used;

(4) A description and depiction of the placement of each plug, including the elevation of the top and bottom of each plug;

(5) The type, grade, and quantity of material to be used in plugging. The material must be compatible with the CO_2 stream; and

(6) The method of plug placement.

(e) The CCS Project Operator must consider the following when developing the Well Plugging and Abandonment Plan:

(1) The location and thickness of the lowermost sequestration zone and freshwater aquifer-containing strata, which dictate the location of all plugs;

(2) Well construction details, particularly the depth of the bottom of the intermediate and surface casings, which would affect the number of plugs and the types and amount of cement needed;

(3) Types of subsurface formations penetrated by the well and their geochemistry, which may influence both plugging methods and the types of cement needed (for open-hole plugging); and

(4) The composition of the CO_2 stream and formation fluid geochemistry, including any geochemical changes anticipated during the post-injection period, which can affect appropriate plugging and cementing materials.

(f) Prior to the well plugging, the CCS Project Operator must flush each CCS injection well with a buffer fluid, determine bottom-hole pressure, and perform a final external mechanical integrity test.

(g) Prior to plugging each well, the CCS Project Operator must consider the operational and monitoring history of the CCS project and identify whether any information or events warrant amendment of the original Well Plugging and Abandonment Plan. Data that must be considered include:

(1) Monitoring data related to chemistry of the CO_2 plume and formation fluids;

(2) Mechanical integrity testing, including any mechanical integrity problems that may have occurred during the injection phase of the CCS project;

(3) Operational data, such as injection rates or volumes; and

(4) Any significant changes to the CCS project that may affect plugging of a well.

(h) Notice of intent to plug: The CCS Project Operator must notify the Executive Officer in writing pursuant to subsection C.1.1.2, at least 30 days before plugging, conversion, or abandonment of a well. At the discretion of the Executive Officer, a shorter notice period may be allowed.

(i) Amending the Well Plugging and Abandonment Plan: If the CCS Project Operator finds it necessary to change the Well Plugging and Abandonment Plan, a revised plan must be submitted at the same time as providing the notice of intent, pursuant to subsection C.1.1.2, to the Executive Officer for written approval.

(j) The CCS Project Operator must receive written approval from the Executive Officer before plugging the well, and must plug and abandon the well in accordance with subsections C.5.1(d) through C.5.1(g) in this section, as provided in the Well Plugging and Abandonment Plan.

(k) Plugging report: Within 60 days after plugging, the CCS Project Operator must submit, pursuant to subsection C.1.1.2, a plugging report to the Executive Officer. The report must be certified as accurate by the CCS Project Operator and by the person who performed the plugging operation (if other than the CCS Project Operator). The CCS Project Operator must retain the well plugging and abandonment report for 10 years following site closure. The report must include:

(1) A statement that the well was plugged in accordance with the Well Plugging and Abandonment Plan previously approved by the Executive Officer; or

(2) If the actual plugging differed from the approved plan, a statement describing the actual plugging and an updated plan specifying the differences from the plan previously submitted; and

(3) A statement that the well was inspected using approved detection methods and found to have no leaks.

(l) Temporary Abandonment: The CCS Project Operator must continue to comply with the conditions of the Permanence Certification, including all monitoring and reporting requirements according to the frequencies outlined in the Permanence Requirements and documentation. The well must also be tested to ensure that it maintains mechanical integrity, according to the requirements and frequency specified in subsection C.4.2.

(1) After a cessation of operations of 24 months, the CCS Project Operator must plug and abandon the well, or group of wells, in accordance with the Executive Officer-approved Well Plugging and Abandonment Plan unless he or she:

(A) Provides notice to CARB; and

(B) Describes actions or procedures, satisfactory to CARB, which the CCS Project Operator will take to ensure that the well will not endanger public health and/or the environment during the period of temporary abandonment. These actions and procedures must include compliance with the technical requirements applicable to active wells unless waived by CARB.

5.2. Post-Injection Site Care and Site Closure

(a) The CCS Project Operator must prepare, maintain, and comply with a plan for post-injection site care and site closure that meets the requirements of subsection C.5.2(a)(2).

(1) The CCS Project Operator must submit the Post-Injection Site Care and Site Closure Plan as a part of the application for Sequestration Site Certification.

(2) Post-Injection Site Care and Site Closure Plan. The plan for site care and closure must include the following information:

(A) The pressure differential between pre-injection and predicted post-injection pressures in the sequestration zone, and the predicted timeframe in which pressure is expected to reach a stable level;

(B) A depiction of the predicted three-dimensional extent of the CO_2 free-phase CO_2 plume and associated elevated pressure at the time of site closure as demonstrated in the final validated computational model required at subsections C.2.4 and C.2.4.1;

(C) A description of post-injection monitoring location, methods, and proposed frequency; and

(D) A proposed schedule for submitting post-injection site care monitoring results to the Executive Officer.

(3) Upon injection completion, the CCS Project Operator must either submit an amended Post-Injection Site Care and Site Closure Plan or demonstrate to the Executive Officer through monitoring data and modeling results that no amendment to the plan is needed. Any amendments to the Post-Injection

Site Care and Site Closure Plan must be approved by the Executive Officer and incorporated into the Permanence Certification.

(4) At any time during the life of the CCS project, the CCS Project Operator may modify and resubmit the Post-Injection Site Care and Site Closure Plan for the Executive Officer's approval.

(b) Post-injection site care and monitoring:

(1) The CCS Project Operator must monitor the site following injection completion to determine the three-dimensional extent of the free-phase CO_2 plume and elevated pressure, and demonstrate that no CO_2 leakage is occurring, as specified in the Testing and Monitoring Plan and the Post-Injection Site Care and Site Closure Plan.

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

(3) Post-injection site care and monitoring requirements are as follows:

(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 subsection C.5.1(d), with the exception of any wells that the CCS Project Operator plans to transition into observation or monitoring wells.

(B) Monitoring and observation wells may remain open, and in active monitoring mode, until the Executive Officer approves of the CCS Project Operator's demonstration that plume stabilization has occurred pursuant to subsection C.5.2(b)(3)(C). Risk reduction must be prioritized, and remote sensing methods and surveillance outside and above the CO_2 plume must be adopted as wells that penetrate the plume are plugged..

(C) No sooner than 15-years post injection completion, the CCS project operator may submit evidence to CARB that plume stabilization has occurred. Such evidence must include modeling pursuant to subsection C.2.4.4, updated using operational and post-injection monitoring measurements. The evidence must also include measured plume migration rates. In order for CARB to determine that plume stabilization has occurred, the evidence must show that plume migration over a 100-year period would not result in CO_2 leakage, that the modeling shows good conformance with measurements, and that overall CO_2 leakage risk is reduced. Following verification, CARB will use the submitted evidence to determine whether plume stabilization has occurred.

(D) If a monitoring well is discovered to be leaking at any time during the post-injection monitoring period, the CCS Project Operator must take all necessary measures to identify the cause of the leak and remediate it. If the leak cannot be remediated, the well must immediately be plugged and abandoned pursuant to subsection C.5.1(d). If necessary, a new well must be drilled to continue monitoring for plume stabilization.

(E) As part of post-injection monitoring, and pursuant to the monitoring timeline as specified in the Post-Injection Site Care and Site Closure Plan, the CCS Project Operator must:

1. Perform quarterly bottom-hole pressure measurements in the monitoring wells in order to track pressure changes. Frequency of measurement may be adjusted based on the previously measured rate of change, provided the CCS Project Operator provides a justification for an alternative monitoring strategy;

2. Use appropriate best-practice methods to map the three dimensional extent of the free-phase CO_2 plume and elevated pressure ; and

3. Periodically update the plume extent modeling pursuant to subsection C.2.4 to determine if any corrective action is necessary and to establish if the CO_2 plume has stabilized.

(F) Once plume stabilization has been determined by CARB to have occurred, pursuant to subsection 5.1(b)(3)(C), all CCS project wells may be abandoned following subsection C.5.1(d).

(G) For the remainder of the post-injection site care and monitoring period following Executive Officer approval of the demonstration of plume stabilization, the CCS Project Operator must implement a leak detection strategy:

1. In the near surface strategically located near plugged and abandoned wells, using ground-based methods. Aerial technologies with a likelihood of detecting leakage from wells in the near-surface equivalent to that of ground-based methods may be used, pending approval of the Executive Officer;

2. At areas of concern determined by the risk assessment (following subsection C.2.2) to be potential pathways for the preferential migration of CO_2 or brine to surface, during the post-injection site care and monitoring period at a frequency based on monitoring and verification data collected during injection and using methods approved by the Executive Officer, at a minimum of once every five years;

3. Using methods that can be verified and provide the following data, at a minimum:

i. Date and time of site visit or visual inspection;

ii. GPS coordinates for any samples collected, measurements recorded, and locations of pertinent areas/points of concern (e.g., plugged and abandoned wells);

iii. Photographs documenting site conditions on date of inspection; and

iv. Appropriate baseline and background measurements collected prior to reaching plume stability.

4. If the inspection checks suggest a potential leak may have occurred, the area must be tested pursuant to subsection C.4.3.2.

(H) The CCS Project Operator must submit the results of all monitoring performed according to the schedule identified in the Post-Injection Site Care and Site Closure Plan.

(c) Notice of intent for site closure. The CCS Project Operator must notify the Executive Officer at least 120 days before site closure. At this time, if any changes have been made to the original Post-Injection Site Care and Site Closure Plan, the CCS Project Operator must also provide the revised plan.

(d) After the Executive Officer has authorized site closure, the CCS Project Operator must plug all monitoring wells as specified in the Post-Injection Site Care and Site Closure Plan, in a manner in which will not allow movement of injection or formation fluids out of the storage complex. At the direction of the Executive Officer, the CCS Project Operator must also restore the site to a condition agreed to with the Executive Officer, as close to pre-injection conditions as practicable.

(e) The CCS Project Operator must submit a site closure report to the Executive Officer within 90 days of site closure, which must thereafter be retained at a location designated by the Executive Officer for 10 years. The report must include:

(1) Documentation of appropriate injection and monitoring well plugging and abandonment as specified in subsections C.5.1, C.5.2(b)(3)(A), and C.5.2(b)(3)(G). The CCS Project Operator must provide a copy of a survey plat, which has been submitted to the local zoning authority designated by the Executive Officer. The plat must indicate the location of the injection well relative to permanently surveyed benchmarks;

(2) Documentation of appropriate notification and information to such state, federal, local, and tribal authorities that have authority over drilling activities to enable such state, federal, local, and tribal authorities to impose appropriate conditions on subsequent drilling activities that may penetrate the storage complex; and

(3) Records reflecting the nature, composition, and volume of the CO_2 stream.

(f) Within six months after completion of injection, each CCS Project Operator must record a notation on the deed to the CCS project property or any other document that is normally examined during title search that will in perpetuity provide any potential purchaser of the property the following information:

(1) The fact that land has been used to sequester CO_2;

(2) The name of the state agency and local authority with which the survey plat was filed; and

(3) The volume of fluid injected, the sequestration zone into which it was injected, and the period over which injection occurred.

(g) The CCS Project Operator must retain for 10 years following site closure, records collected during the post-injection site care period.

6. Emergency and Remedial Response

(a) As part of the application for Sequestration Site Certification, the CCS Project Operator must provide the Executive Officer with an Emergency and Remedial Response Plan that describes actions the CCS Project Operator must take in the event of an emergency at the site that has the potential to endanger public health or the environment during construction, operation, and post-injection site care periods.

(b) If the CCS Project Operator obtains evidence any CCS project operations have the potential to endanger public health or the environment, either by surface injection facility operations or CO_2 or formation fluid leakage, the CCS Project Operator must:

(1) Immediately cease injection in affected well(s) and any other wells that may exacerbate risk of leakage in the affected well(s);

(2) Take all steps reasonably necessary to identify, characterize, and quantify any CO_2 leakage;

(3) Notify the Executive Officer in writing within 24 hours; and

(4) Implement the Emergency and Remedial Response Plan.

(c) The Executive Officer may allow the CCS Project Operator to resume injection prior to remediation if the CCS Project Operator demonstrates that the injection operation will not endanger public health and the environment.

(d) The CCS Project Operator must periodically review the Emergency and Remedial Response Plan developed under subsection C.6(a), which must include:

(1) At a frequency specified in the Storage Complex and Corrective Action Plan, or more frequently when monitoring, operational, or other relevant conditions warrant, the CCS Project Operator must review and update the Emergency and Remedial Response Plan or demonstrate to the Executive officer that no update is needed. The CCS Project Operator must also incorporate monitoring, operational data, or other relevant data and in response to storage complex reevaluations required under subsection C.2.4.4 or demonstrate to the Executive Officer that no update is needed. The amended Emergency and Remedial Response Plan or demonstration must be submitted to the Executive Officer as follows:

(A) Within one year of a storage complex reevaluation;

(B) Following any significant changes to the CCS project, such as addition of injection or monitoring wells, on a schedule determined by the Executive Officer; or

(C) When required by the Executive Officer.

(e) Following each update of the Emergency and Remedial Response Plan or a demonstration that no update is needed, the CCS Project Operator must submit the resultant information to the Executive Officer for review and confirmation of the results.

6.1. Emergency and Remedial Response Requirements

(a) The Emergency and Remedial Response Plan must describe the response actions that would be necessary in the event of an emergency at the site. The plan must ensure that site operators know which entities and individuals are to be notified and what actions need to be taken to mitigate an emergency situation and protect public health and safety and the environment. The Emergency and Remedial Response Plan must be based on the site risk assessment pursuant to subsection C.2.2.

(b) Response actions should depend on the severity of the event(s) that triggered an emergency response. Emergency events are characterized in Table 3.

Table 2. Degrees of risk for emergency events

Emergency Condition	**Description**
Major Emergency	Event poses immediate substantial risk to human health, resources, or infrastructure. Emergency actions involving local authorities (evacuation or isolation of areas) should be initiated.
Serious Emergency	Event poses potential serious (or significant) near term risk to human health, resources, or infrastructure if conditions worsen or no response actions are taken.
Minor Emergency	Event poses no immediate risk to human health, resources, or infrastructure.

(c) The Emergency and Remedial Response Plan must include the following:

(1) A list and description of possible risk scenarios that could potentially call for emergency response at the site, including but not limited to:

(A) Injection, production, or monitoring well integrity failure;

(B) Well injection or monitoring equipment failure;

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

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

(E) Induced seismic event.

(2) A list and description of the potential consequences of the risk scenarios.

(3) A list and description of local resources and infrastructure that may be impacted as a result of an emergency at the CCS project site, including but not limited to:

(A) Freshwater aquifers, potable water wells, surface water such as rivers or lakes, farmland, and public land or nature preserves; and

(B) Residential areas, commercial properties, recreational facilities, topographic depressions, and basements.

(4) A list and description of any steps needed to identify, characterize, and respond to each potential risk scenario listed pursuant to subsection C.6.1(a)(1) in this section, including:

(A) Emergency identification, for example:

1. Activation of automatic shutdown devices due to well integrity failure;

2. Malfunction of monitoring equipment for pressure or temperature that may indicate a problem with the injection well and possible endangerment of public health and the environment;

3. Detections of elevated concentrations of CO_2 or other evidence of CO_2 leakage to the land surface;

4. Detections of elevated values of indicator parameters in groundwater samples or other evidence of brine or CO_2 leakage into freshwater aquifers or surface water; or

5. A natural disaster such as a weather-related disaster that may impact surface facilities or an earthquake that may disturb subsurface facilities.

(B) Response actions planned, including but not limited to:

1. Notification to the site supervisor or designee;

2. Notification to the Executive Officer in writing within 24 hours of the emergency event, per subsection C.6(b)(3);

3. Initial assessment of the situation by the site supervisor or designee and the determination of which other CCS project personnel to notify;

4. The determination of the severity of the event, based on the information available by the site supervisor or designee, within 24 hours of the event; and

5. Emergency and remedial actions to be taken to stop or limit the risk of endangerment to public health and the environment due to the type and severity of the event.

(5) A list of site personnel, CCS project personnel, and local authorities, and their contact information.

(6) A list of any special equipment needed in the event of an emergency. The type of equipment needed in the event of an emergency, as remedial

response varies depending on the triggering event. Response actions (e.g., injection completion or hiatus, well shut-in, or evacuation) will generally not require specialized equipment to implement. Where specialized equipment (such as a drilling rig) is required, the designated Project Manager must be responsible for its procurement.

(7) A site-specific emergency communications plan, including the designation of a public and media communications liaison, which must be developed and maintained throughout the life of the CCS project.

(8) The timeline for review of the Emergency and Remedial Response Plan, no less than once every five years following its approval by the permitting agency, within one year following a storage complex reevaluation, and within a prescribed period to be determined by CARB following any significant changes to the injection process or CCS project. If the review indicates that no amendments to the Emergency and Remedial Response Plan are necessary, the CCS Project Operator must provide the Executive Officer with documentation supporting such a determination. If the review indicates that amendments to the Emergency and Remedial Response Plan are necessary, amendments must be made and submitted to the CARB within one year following an event that initiates the Emergency and Remedial Response Plan review procedure.

7. Financial Responsibility

(a) The CCS Project Operator of a certified CCS project must demonstrate and maintain financial responsibility and resources as determined by the Executive Officer that meets the following conditions:

(1) The financial responsibility instrument(s) used must be from the following list of qualifying instruments:

(A) Trust Funds;

(B) Surety Bonds;

(C) Letter of Credit;

(D) Insurance;

(E) Self-Insurance (i.e., Financial Test and Corporate Guarantee);

(F) Escrow Account; and

(G) Any other instrument(s) satisfactory to the Executive Officer.

(2) The qualifying instrument(s) must be sufficient to cover the cost of:

(A) Corrective action (that meets the requirements of subsection C.2.4.3);

(B) Well plugging and abandonment (that meets the requirements of subsection C.5.1);

(C) Post-injection site care and site closure (that meets the requirements of subsection C.5.2); and

(D) Emergency and remedial response (that meets the requirements of subsection C.6).

(3) The financial responsibility instrument(s) must be sufficient to address the potential endangerment of public health and the environment via atmospheric CO_2 leakage.

(4) The qualifying financial responsibility instrument(s) must comprise protective conditions of coverage.

(A) Protective conditions of coverage must include at a minimum: cancellation, renewal, and continuation provisions, specifications on when the provider becomes liable following a notice of cancellation if there is a failure to renew (with a new qualifying financial instrument), as well as requirements for the provider to meet a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.

1. For purposes of this part, a CCS Project Operator must provide that their financial mechanism may not cancel, terminate or fail to renew except for failure to pay such financial instrument. If there is a failure to pay the financial instrument, the financial institution may elect to cancel, terminate, or fail to renew the instrument by sending notice by certified mail and an electronic format to the CCS Project Operator and the Executive Officer. The cancellation must not be final for 120 days after receipt of cancellation notice. The CCS Project Operator must provide an alternate financial responsibility demonstration within 60 days of notice of cancellation, and if an alternate financial responsibility demonstration is not acceptable (or possible), any funds from the instrument being cancelled must be released within 60 days of notification by the Executive Officer to complete required activities that the financial responsibility instrument are expected to cover, as described in subsection C.7(a)(2).

2. For purposes of this part, the CCS Project Operator must renew all financial instruments, if an instrument expires, for the entire term of the

CCS project. The instrument may be automatically renewed as long as the CCS Project Operator has the option of renewal at the face amount of the expiring instrument. The automatic renewal of the instrument must, at a minimum, provide the holder with the option of renewal at the face amount of the expiring financial instrument.

3. Cancellation, termination, or failure to renew may not occur and the financial instrument will remain in full force and effect in the event that on or before the date of expiration: (1) the Executive Officer deems the CCS project abandoned, (2) the permit is terminated or revoked or a new permit is denied, (3) closure is ordered by the Executive Officer or a U.S. district court or other court of competent jurisdiction, (4) the CCS Project Operator is named as debtor in a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code, or (5) the amount due is paid.

(5) The qualifying financial responsibility instrument(s) must be approved by the Executive Officer.

(A) The financial responsibility demonstration must be considered and approved by the Executive Officer for all phases of the CCS project prior to Permanence Certification following subsection C.1.1.

(B) The CCS Project Operator must provide updated information related to their financial responsibility instrument(s) when/if there are any changes. This information must be provided to the Executive Officer within 30 days of such a change. The Executive Officer will evaluate, within a reasonable time, the financial responsibility demonstration to confirm that the instrument(s) used remain adequate for use. The CCS Project Operator must maintain financial responsibility requirements regardless of the status of the Executive Officer's review of the financial responsibility demonstration.

(C) The Executive Officer may disapprove the use of a financial instrument if they determine that it is not sufficient to meet the requirements of this section.

(6) The CCS Project Operator must demonstrate financial responsibility by using one or multiple qualifying financial instruments for specific phases of the CCS project.

(A) In the event that the CCS Project Operator combines more than one instrument for a specific CCS phase (e.g., well plugging), such combination must be limited to instruments that are not based on financial strength or performance (i.e., self-insurance or performance bond), for example trust funds, surety bonds guaranteeing payment into a trust fund,

letters of credit, escrow account, and insurance. In this case, it is the combination of mechanisms, rather than the single mechanism, which must provide financial responsibility for an amount at least equal to the current cost estimate.

(B) When using a third-party instrument to demonstrate financial responsibility, the CCS Project Operator must provide a proof that the third-party providers either have passed financial strength requirements based on credit ratings, or has met a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.

(C) A CCS Project Operator using certain types of third-party instruments must establish a standby trust to enable CARB to be party to the financial responsibility agreement without CARB being the beneficiary of any funds. The standby trust fund must be used along with other financial responsibility instruments (e.g., surety bonds, letters of credit, or escrow accounts) to provide a location to place funds if needed.

(D) A CCS Project Operator may deposit money to an escrow account to cover financial responsibility requirements, and this account must segregate funds sufficient to cover estimated costs for CCS project financial responsibility from other accounts and uses.

(E) A CCS Project Operator or its guarantor may use self-insurance to demonstrate financial responsibility for CCS projects. In order to satisfy this requirement the CCS Project Operator must meet a tangible net worth of an amount approved by the Executive Officer, have a Net working capital and tangible net worth each at least six times the sum of the current well plugging, post injection site care and site closure cost, have assets located in the United States amounting to at least 90 percent of total assets or at least six times the sum of the current well plugging, post injection site care and site closure cost, and must submit a report of its bond rating and financial information annually. In addition the CCS Project Operator must either: Have a bond rating test of AAA, AA, A, or BBB as issued by Standard & Poor's, Aaa, Aa, A, or Baa as issued by Moody's, or meet all of the following five financial ratio thresholds:

1. A ratio of total liabilities to net worth less than 2.0;

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

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

4. A ratio of current assets minus current liabilities to total assets greater than =0.1; and

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

(F) A CCS Project Operator who is not able to meet corporate financial test criteria may arrange a corporate guarantee by demonstrating that its corporate parent meets the financial test requirements on its behalf. The parent's demonstration that it meets the financial test requirement is insufficient if it has not also guaranteed to fulfill the obligation for the CCS Project Operator.

(G) A CCS Project Operator may obtain an insurance policy to cover the estimated costs of CCS activities requiring financial responsibility. This insurance policy must be obtained from a third-party provider.

(b) The CCS Project Operator must maintain financial responsibility and resources until:

(1) The Executive Officer receives and approves the completed Post-Injection Site Care and Site Closure Plan; and

(2) The Executive Officer approves site closure.

(c) The CCS Project Operator may be released from financial instrument in the following circumstances:

(1) The CCS Project Operator has completed the phase of the CCS project for which the financial instrument was required and has fulfilled all its financial obligations as determined by the Executive Officer, including obtaining financial responsibility for the next phase of the CCS project, if required; or

(2) The CCS Project Operator has submitted a replacement financial instrument and received written approval from the Executive Officer accepting the new financial instrument and releasing the CCS Project Operator from the previous financial instrument.

(d) The CCS Project Operator must have a detailed written estimate, in current dollars, of the cost of performing corrective action on 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.

(1) The cost estimate must be performed for each phase separately and must be based on the costs to the regulatory agency of hiring a third party to perform the required activities. A third party is a party who is not within the corporate structure of the CCS Project Operator.

(2) During the active life of the CCS project, the CCS Project Operator must adjust the cost estimate for inflation within 60 days prior to the anniversary date of the establishment of the financial instrument(s) used to comply with subsection C.7(a) and provide this adjustment to the Executive Officer. The CCS Project Operator must also provide the Executive Officer written updates of adjustments to the cost estimate within 60 days of any amendments to the Corrective Action Plan, the Well Plugging and Abandonment Plan, the Post-Injection Site Care and Site Closure Plan, and the Emergency and Remedial Response Plan.

(3) Any decrease or increase to the initial cost estimate must be approved by the Executive Officer. During the active life of the CCS project, the CCS Project Operator must revise the cost estimate no later than 60 days after the Executive Officer has approved the request to modify the Corrective Action Plan, the Injection Well Plugging and Abandonment Plan, the Post-Injection Site Care and Site Closure Plan, and the Emergency and Remedial Response Plan, if the changes in the plan increases the cost. If the change to the plans decreases the cost, any withdrawal of funds must be approved by the Executive Officer. Any decrease to the value of the financial assurance instrument must first be approved by the Executive officer. The revised cost estimate must be adjusted for inflation as specified at subsection C.7(c)(2).

(4) Whenever the current cost estimate increases to an amount greater than the face amount of a financial instrument currently in use, the CCS Project Operator, within 60 days after the increase, must either cause the face amount to be increased to an amount at least equal to the current cost estimate and submit evidence of such increase to the Executive Officer, or obtain other financial responsibility instruments to cover the increase. Whenever the current cost estimate decreases, the face amount of the financial assurance instrument may be reduced to the amount of the current cost estimate only after the CCS Project Operator has received written approval from the Executive Officer.

(e) The CCS Project Operator must notify the Executive Officer by an electronic format and certified mail of adverse financial conditions such as bankruptcy that may affect the ability to carry our injection well plugging and post-injection site care and site closure.

(1) In the event that the CCS Project Operator or the third-party provider of a financial responsibility instrument is going through a bankruptcy, the CCS Project Operator must notify the Executive Officer by certified mail and an electronic format of the commencement of a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code, naming the CCS Project Operator as debtor, within 10 days after commencement of the proceeding.

(2) A guarantor of a corporate guarantee must make such a notification to the Executive Officer if he/she is named as debtor, as required under the terms of the corporate guarantee.

(3) A CCS Project Operator who fulfills the requirements of subsection C.7(a) by obtaining a trust fund, surety bond, letter of credit, escrow account, or insurance policy will be deemed to be without the required financial assurance in the event of bankruptcy of the trustee or issuing institution, or a suspension or revocation of the authority of the trustee institution to act as trustee of the institution issuing the trust fund, surety bond, letter of credit, escrow account, or insurance policy. The CCS Project Operator must establish other financial assurance within 60 days after such an event.

(f) The CCS Project Operator must provide an adjustment of the cost estimate to the Executive Officer within 60 days of notification by the Executive Officer, if the Executive Officer determines during the annual evaluation of the qualifying financial responsibility instrument(s) that the most recent demonstration is no longer adequate to cover the cost of corrective action (as required by subsection C.2.4.3), well plugging and abandonment (as required by subsection C.5.1), post-injection site care and site closure (as required by subsection C.5.2), and emergency and remedial response (as required by subsection C.6).

(g) The use and length of pay-in-periods for trust funds or escrow accounts must be approved by the Executive Officer.

8. Modification or Revocation and Reissuance of Permanence Certification

(a) When the Executive Officer receives any information, including but not limited to, (1) information submitted by the CCS Project Operator as required by the Permanence Certification, (2) receives a request for modification or evocation and reissuance of the Permanence Certification, or (3) inspects the facility or conducts a review of the Permanence Certification, he or she may determine whether or not one or more of the causes listed in subsections C.8(b) and C.8(c) of this section exist requiring a modification or revocation and reissuance of the Permanence Certification, or both. If cause exists, the Executive Officer may modify or revoke and reissue the Permanence Certification accordingly, and may request an updated Permanence Certification if necessary. When a Permanence Certification is modified, only the conditions subject to modification are reopened. If a Permanence Certification is revoked and reissued, the entire Permanence Certification is reopened and subject to revision and the permit is reissued for a new term. If a Permanence Certification modification satisfies the criteria in subsection C.8.2 for "minor modifications," the Permanence Certification may be modified without a draft Permanence Certification and public review. Otherwise, the Executive Officer will post the draft Permanence Certification for public comment for at least 15 days, address those comments if considered valid, and

then issue an executive order endorsing the permanence of the CCS project, if appropriate.

(b) Causes for modification or revocation and reissuance.

(1) Alterations. There are material and substantial alterations or additions to the certified CCS project or activity which occurred after issuance of the Permanence Certification, and which justify the application of conditions that are different or absent in the existing Permanence Certification.

(2) Information. Permanence Certifications may be modified during their terms for this cause only if the information was not available at the time of issuance of the Permanence Certification (other than revised regulations, guidance, or test methods) and would have justified the application of different conditions of Permanence Certification at the time of issuance.

(3) New regulations. The standards or regulations on which the Permanence Certification was based have been changed by promulgation of new or amended standards or regulations or by judicial decision after the Permanence Certification was issued.

(4) Compliance schedules. The Executive Officer determines good cause exists for modification of a compliance schedule, such as a strike, flood, or materials shortage or other events over which the certified CCS Project Operator has little or no control and for which there is no reasonably available remedy. (See also subsection C.8.2(a)(3)).

(5) Basis for modification of Permanence Certifications. Additionally, whenever the Executive Officer determines that changes to the Permanence Certification are necessary, based on:

(A) Storage complex reevaluations under subsection C.2.4.4;

(B) Any amendments to the Testing and Monitoring Plan under subsection C.4.1;

(C) Any amendments to the Well Plugging and Abandonment Plan under subsection C.5.1;

(D) Any amendments to the Post-Injection Site Care and Site Closure Plan under subsection C.5.2;

(E) Any amendments to the Emergency and Remedial Response Plan under subsection C.6;

(F) A review of monitoring and/or testing results conducted in accordance with Permanence Certification requirements.

(c) Causes for modification or revocation and reissuance of Permanence Certification. Cause exists to modify or, alternatively, revoke and reissue Permanence Certification if the Executive Officer determines cause exists for termination under subsection C.8.1(a), and the Executive Officer determines that modification or revocation and reissuance is appropriate.

8.1. Termination of Permanence Certifications

(a) The Executive Officer may terminate a Permanence Certification during its term, or deny a Permanence Certification renewal application for the following causes:

(1) Noncompliance by the CCS Project Operator with any condition of the Permanence Certification;

(2) The CCS Project Operator's failure in the application or during the Permanence Certification issuance process to disclose fully all relevant facts, or the CCS Project Operator's misrepresentation of any relevant facts at any time; or

(3) A determination that any CCS injection activity endangers public health or the environment via CO_2 or formation fluid leakage, and can only be regulated to acceptable levels by modification or termination of Permanence Certification.

8.2. Minor Modification of Permanence Certifications

(a) Upon the consent of the CCS Project Operator, the Executive Officer may modify a Permanence Certification to make the corrections or allowances for changes in the certified CCS project activity listed in this section, without following the procedures of subsection C.8(a). Any modification to the Permanence Certification not processed as a minor modification under this section must be made for cause and pursuant to draft Permanence Certification and public notice as required in subsection C.8(a). Minor modifications may only:

(1) Correct typographical errors;

(2) Require more frequent monitoring or reporting by the CCS Project Operator;

(3) Change an interim compliance date in a schedule of compliance, provided the new date is not more than 120 days after the date specified in the existing Permanence Certification and does not interfere with attainment of the final compliance date requirement; or

(4) Allow for a change in ownership or operational control of a CCS project where the Executive Officer determines that no other change in Permanence Certification is necessary, provided that a written agreement containing a specific date for transfer of responsibility, coverage, and liability between the current and new CCS Project Operator has been submitted to the Executive Officer.

(5) Change quantities or types of fluids injected which are within the capacity of the facility as certified and, in the judgment of the Executive Officer, would not interfere with the operation of the CCS project or its ability to meet conditions described in the Permanence Certification.

(6) Change in construction requirements approved by the Executive Officer, provided that any such alteration must comply with the requirements of this section and subsection C.3.1.

(7) Amend a plugging and abandonment plan which has been updated under subsection C.5.

(8) Amend a CCS Well Testing and Monitoring Plan, Plugging Plan, Post-Injection Site Care and Site Closure Plan, or Emergency and Remedial Response Plan where the modifications merely clarify or correct the plan, as determined by the Executive Officer.

9. Legal Understanding, Contracts, and Post-Closure Care

(a) The CCS Project Operator must show proof of exclusive right to use the pore space in the sequestration zone for storing CO_2 permanently;

(b) Full disclosure must be made to inform future land management or development within the surface projection of the storage complex. 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; and

(4) The CCS Project Operator must show 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. A separate verification statement is not required for the CCS Project. The material misstatement evaluation and conformance review will be included in the verification statement for LCFS.

(c)

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Appendix A. Fugitive and Vented GHG Emissions: Injection into Depleted Oil and Gas and Saline Formations

(a) Fugitive CO_2 Emissions: Equipment Count Method

Count each component (e.g., valves, connectors, open-ended lines) individually for the facility and multiply with default emission factors specific to component type. Alternatively, count the number of major pieces of equipment and multiply by the average number of components per major piece of equipment to arrive at the total number of each component for a facility. Calculate fugitive CO_2 emissions using Equation A.1.

$$E_{s,i} = \sum Count_i \times EF_i \times C_{CO2} \times T_s \quad \text{(A.1)}$$

Where:

~~$E_{s,i}$ = Annual volumetric fugitive CO_2 emissions at standard conditions from i^{th} component in cubic feet.~~

~~$Count_i$ = Total number of i^{th} component at the facility.~~

~~EF_i = Emission factor for i^{th} component (scf/hour). Use a default CO_2 emission factor if available. Methane emission factors can be used as proxy for CO_2 emission factors.~~

~~C_{CO2} = CO_2 concentration (%).~~

~~T_s = Total time that each component type associated with the equipment leak emission was operational per year, in hours, using engineering estimate based on best available data.~~

$E_{s,i}$ = Volumetric fugitive CO_2 emissions at standard conditions from i^{th} component type in cubic feet per reporting timeframe.

$Count_i$ = Total number of i^{th} component type at the facility. If project specific component counts are not available, the component count values from Table E5 must be used. If the equipment type is not available in Table E5, the applicant must apply to CARB for a method to determine component counts.

EF_i = Emission factor for i^{th} component type (scf/hour/component). Use the CO_2 values from Table E4. Any component type not listed in Table E4 must use the "Other" component type. Methane emission factors can be used as proxy for CO_2 emission factors.

C_{CO2} = CO_2 concentration (%)

T_s = Total time that each component type associated with the equipment leak emission was operational per reporting timeframe, in hours. Unless monitored the default value of 8,760 hours will be used.

$E_{s,i}$ must be converted to MT CO_2/year or MT CO_2/quarter using the method described in Appendix C to obtain estimate $CO_{2_{fugitive}}$ included in previous equations.

(b) Vented Emissions: Event-Based Approach

Calculate vented CO_2 emissions by measuring/estimating CO_2 emissions per venting event, and account for CH_4 emissions for all venting events at storage site per ~~year~~reporting timeframe using Equation A.2.

$$GHG_{vent} = \sum_{i=1}^{n} Vi \quad \text{(A.2)}$$

Where:

~~GHG_{vent} = Annual vented CO_2 and CH_4 emissions (MT CO_2e/year).~~
~~Vi = Vented CO_2 and CH_4 emissions for i^{th} vented event (MT CO_2e/event).~~

GHG_{vent} = Vented CO_2 and CH_4 emissions (MT CO_2e/year or MT CO_2e/quarter).

V_i = Vented CO_2 and CH_4 emissions for i^{th} vented event (MT CO_2e/event).

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Appendix B. CO_2 Venting and Fugitive Emissions from CO_2-EOR Operations

(a) Metered natural gas pneumatic device and pump vented CO_2 emissions.

(1) Calculate CO_2 emissions from a natural gas-powered continuous high bleed control device and pneumatic pump vented using the method specified ~~insection~~in section 95153(a) in the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (MRR)[12] when the natural gas flow to the device is metered.

(b) Non-metered natural gas pneumatic device vented emissions.

(1) Calculate CO_2 emissions from all non-metered natural gas-powered pneumatic intermittent bleed and continuous low and high bleed devices using the equation in section 95153(a) of MRR.

(c) Acid gas removal vents.

(1) For AGR vents (including processes such as amine, membrane, molecular sieve or other absorbents and adsorbents), calculate emissions for CO_2 only (not CH_4) vented directly to the atmosphere or emitted through a flare, engine (e.g., permeate from a membrane or de-adsorbed gas from a pressure swing adsorber used as fuel supplement), or sulfur recovery plant using the applicable calculation methodologies described in section 95153(c) of MRR.

(d) Dehydrator vents.

(1) Calculate annual CO_2 emissions using any of the calculation methodologies described in section95153(d) of MRR.

(e) Gas well vented CO_2 emissions during well completions and workovers.

(1) Use either the Methodology 1 or 2 described in section 95153(f) of MRR.

(f) Equipment and pipeline blowdowns.

(1) Calculate CO_2 blowdown emissions from depressurizing equipment and natural gas pipelines to reduce system pressure for shutdowns resulting from human intervention or to take equipment out of service for maintenance (excluding depressurizing to a flare, over-pressure relief, operating pressure control vented and blowdown of non-GHG gases using the methods described in 95153(g). Desiccant dehydrator blowdown vented before reloading is covered in section 95153 (d) of MRR.

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[12] Final Regulation Order, Amendments to the Regulation, Mandatory Reporting of Greenhouse Gas Emissions Regulation. CARB, filed with Secretary of State September 1, 2017.

(g) Dump valves.

(1) Calculate CO_2 emissions from gas-liquid separator liquid dump valves not closing by using the method found in section 95153(i) of MRR.

(h) Well testing vented emissions.

(1) Calculate CO_2 vented from oil well testing using the methods found in section 95153(j) of MRR.

(i) Associated gas.

(1) Calculate CO_2 in associated gas vented not in conjunction with well testing using the methods found in section 95153(k) of MRR.

(j) Centrifugal compressor vented emissions.

(1) Calculate CO_2 emissions from both wet seal and dry seal centrifugal compressor using the methods described in section 95153(m) of MRR.

(k) Reciprocating compressor vented emissions.

(1) Calculate CO_2 emissions from all reciprocating compressor vents using the methods described in section 95153 of MRR.

(l) EOR injection pump blowdown emissions.

(1) Calculate CO_2 pump blowdown emissions from EOR operations using critical CO_2 injection using Equation 33 as described in section 95153(u) of MRR.

(m) Fugitive CO_2 emissions from valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other equipment leak sources (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps).

(1) Perform leak detection tests in accordance with procedures as described in the MRR. If CO_2 leakage is detected from the equipment listed above during annual leak detection tests, calculate fugitive emissions (CO_2) per component type in which leak is detected using Equation 25 in section 95153(o) of MRR for each component type. Default fugitive emission factors for Equation 25 are reported in Tables E4 to E6; or

(2) Calculate fugitive emissions from all equipment using the population count and emission factors as described in section 95153(p) of MRR.

Appendix C. Converting Volume of CO_2 to Mass

(a) When volumetric emissions of CH_4 and CO_2 are measured at actual temperatures and pressures, convert them to volumetric emissions at standard conditions (25˚C and 1 atm) using ~~Equation30~~Equation 30 in MRR~~2~~.

(b) Calculate GHG mass emissions by converting the GHG volumetric emissions at standard conditions into mass emissions using Equation 32 described in section 95153(t) of MRR.

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Appendix D. Data Measurement/Generation and Reporting for Energy and Chemical Inputs

(a) Amounts of fuels used:

(1) Fuel receipts/invoices or flow meter readings whichever applicable;

(2) The flow meter readings must be corrected for temperature and pressure. Density estimates used for emission quantification purposes must be adjusted to corrected standardized temperatures and pressures;

(3) Flow meters must be placed based on manufacturer recommendations and must operate within manufacturers specified operating conditions at all times; and

(4) Flow meters must be calibrated according to manufacturer specifications and must be checked and calibrated at regular intervals according to these specifications.

(5) In cases where the same fuel is used for CCS and other unrelated activities and share the same meter or receipts/invoices, or when fuel receipts/invoices or metered data are not available, estimates with justification for the chosen methodology can be used with approval from ~~the Executive Officer.~~CARB.

(b) Electricity consumption:

(1) Utility receipts/invoices or metered data for off-grid electricity use. ~~-~~In the absence of these data, maximum power rating for each type of equipment and operating hours can be used to estimate electricity use with approval from ~~the Executive Officer~~CARB.

(2) In certain cases, other loads may be tied into the same electricity meter.~~-~~ In such instances, estimates with justification for the chosen methodology can be used with approval from ~~the Executive Officer~~CARB.

(3) Electricity meters must be calibrated in accordance with manufacturer specifications and must be checked and calibrated at regular intervals according to these specifications.

(c) Steam consumption:

(1) Utility receipts/invoices or metered data for on-site steam production whichever applicable.

(2) In the absence of utility receipts/invoices or metered data, estimates with justification for the chosen methodology can be used with approval from ~~the Executive Officer~~CARB.

(3) If metered data are used, meters must be calibrated in accordance with manufacturer specifications and must be checked and calibrated at regular intervals according to these specifications.

(d) Cogeneration:

If any part of the CCS project uses electricity and thermal energy steam supplied directly by co-generation, the amount of fuel use associated with the electricity and thermal energy steam must be estimated using Equations D.1 and D.2.

$$Fuel_{electricity} = Total\ Fuel_{cogen} \times \frac{Heat_{CCS} + Electricity_{CCS}}{Heat_{cogen} + Electricity_{cogen}} \times f_{electricity} \quad \text{(D.1)}$$

$$Fuel_{steam} = Total\ Fuel_{cogen} \times f_{steam} \quad \text{(D.2)}$$

Where:

~~$Fuel_t$ = Proportionate volume or mass of each type of fuel, by fuel type i, combusted by cogeneration unit to supply electricity or thermal energy to the CCS project (e.g., gallons/year or metric tons/year).~~

~~$Total\ Fuel_{cogen}$ = Total volume or mass of each type of fuel, by fuel type i, combusted by the cogeneration unit supplying electricity or thermal energy to the CCS project (e.g., gallons/year or metric tons/year).~~

~~$Heat_{CCS}$ = Quantity of thermal energy supplied to the CCS project by the cogeneration unit (MJ/year).~~

~~$Electricity_{CCS}$ = Quantity of electricity supplied to the CCS project by the cogeneration unit (MWh/year).~~

~~$Heat_{cogen}$ = Total quantity of thermal energy generated by the cogeneration unit (MJ/year).~~

~~$Electricity_{cogen}$ = Total quantity of electricity generated by the third party cogeneration unit (MWh/year).~~

$Fuel_{electricity}$ = Amount of fuel attributed to electricity production in mmbtu.

$Fuel_{steam}$	=	Amount of fuel attributed to steam production in mmbtu.
$Total\ Fuel_{cogen}$	=	Total fuel combusted by the cogeneration unit supplying electricity and/or stream to the CCS Project.
$f_{electricity}$	=	$\frac{\frac{Electricity\ Generation}{0.35}}{\frac{Electricity\ Generation}{0.35} + \frac{Steam\ \ Generation}{0.8}}$
f_{steam}	=	1- $f_{electricity}$

Where, $f_{electricity}$ and f_{steam} are the allocation factors for electricity and steam, respectively. Electricity Generation represents total electricity (mmbtu) produced by the co-generation unit. Steam Generation represents the energy (mmbtu) of the steam generated from the available exhaust heat from the co-generation unit.

(e) Chemical inputs:

(1) Purchase receipts/invoices or flow meter readings whichever applicable.

Appendix E. Emission Factors and Component Counts

Note: Stationary emissions factors in Tables E1 to E3 may be used only if they are not available in CA-GREET.

Table E1. Stationary Emission Factors for Fossil Fuel Combustion[13]

Coal and Coke	**kg CO_2/ton**	**g CH_4/ton**	**g N_2O/ton**
Anthracite (coal)	2602	276	40
Bituminous (coal)	2325	274	40
Sub-bituminous (coal)	1676	190	28
Lignite	1389	156	23
Mixed (commercial)	2016	235	34
Mixed (electric power sector)	1885	217	32
Mixed (industrial sector)	2468	289	42
Mixed (commercial)	2116	246	36
Coal Coke	2819	273	40
Fossil-derived Fuels (solid)	**kg CO_2/ton**	**g CH_4/ton**	**g N_2O/ton**
Municipal Solid Waste	902	318	42
Petroleum Coke (Solid)	3072	960	126
Plastics	2850	1216	160
Tires	2407	896	118
Fossil-derived Fuels (gaseous)	**kg CO_2/scf**	**g CH_4/scf**	**g N_2O/scf**
Blast Furnace Gas	0.02524	0.000002	0.000009
Coke Oven Gas	0.02806	0.000288	0.00006
Fuel Gas	0.08189	0.004164	0.000833
Propane Gas	0.15463	0.000055	0.000252

Note: Ton refers to short ton. While using Tables E1 to E3, CO and VOC emissions may need to be estimated if possible.

[13] US EPA. Direct Emissions from Stationary Combustion Sources. (2016). Available at https://www.epa.gov/sites/production/files/2016-03/documents/stationaryemissions_3_2016.pdf

Table E2. Stationary Emission Factors for Petroleum Fuel ~~Combustion~~Combustion[3]

Petroleum Products	kg CO_2/gal	g CH_4/gal	g N_2O/gal
Asphalt and Road Oil	11.91	0.47	0.09
Aviation Gasoline	8.31	0.36	0.07
Butane	6.67	0.31	0.06
Butylene	7.22	0.32	0.06
Crude Oil	10.29	0.41	0.08
Distillate Fuel Oil No .1	10.18	0.42	0.08
Distillate Fuel Oil No .2	10.21	0.41	0.08
Distillate Fuel Oil No. 4	10.96	0.44	0.09
Ethane	4.05	0.2	0.04
Ethylene	3.83	0.17	0.03
Heavy Gas Oils	11.09	0.44	0.09
Isobutane	6.43	0.3	0.06
Isobutylene	7.09	0.31	0.06
Kerosene	10.15	0.41	0.08
Kerosene-Type Jet Fuel	9.75	0.41	0.08
Liquefied Petroleum Gases (LPG)	5.68	0.28	0.06
Lubricants	10.69	0.43	0.09
Motor Gasoline	8.78	0.38	0.08
Naphtha (<401 deg F)	8.5	0.38	0.08
Natural Gasoline	7.36	0.33	0.07
Other Oil (>401 deg F)	10.59	0.42	0.08
Pentanes Plus	7.7	0.33	0.07
Petrochemical Feedstocks	8.88	0.38	0.08
Petroleum Coke	14.64	0.43	0.09
Propane	5.72	0.27	0.05
Propylene	6.17	0.27	0.05
Residual Fuel Oil No. 5	10.21	0.42	0.08
Residual Fuel Oil No. 6	11.27	0.45	0.09
Special Naphtha	9.04	0.38	0.08
Unfinished Oils	10.36	0.42	0.08
Used Oil	10.21	0.41	0.08

Table E3. Stationary Emission Factors for Petroleum Fuel ~~Combustion~~Combustion[3]

Biomass-Derived Fuels (Solid)	**kg CO_2/ton**	**g CH_4/ton**	**g N_2O/ton**
Agricultural Byproducts	975	264	35
Peat	895	256	34
Solid Byproducts	1096	332	44
Wood and Wood Residuals	1640	126	63
Biomass -Derived Fuels (gaseous)	**kg CO_2/scf**	**g CH_4/scf**	**g N_2O/scf**
Landfill Gas	0.025254	0.001552	0.000306
Other Biomass Gases	0.034106	0.002096	0.000413
Biomass Fuels (liquid)	**kg CO_2/gal**	**g CH_4/gal**	**g N_2O/gal**
Biodiesel (100%)	9.45	0.14	0.01
Ethanol (100%)	5.75	0.09	0.01
Rendered Animal Fat	8.88	0.14	0.01
Vegetable Oil	9.79	0.13	0.01
Biomass Fuels (Kraft Pulping Liquor by Wood Furnish)	**kg CO_2/MMbtu**	**g CH_4/MMbtu**	**g N_2O/MMbtu**
North American Softwood	94.4	1.9	0.42
North American Hardwood	93.7	1.9	0.42
Bagasse	95.5	1.9	0.42
Bamboo	93.7	1.9	0.42
Straw	95.1	1.9	0.42

Table E4. Default CO_2 Emission ~~Factors for Onshore Petroleum and Natural Gas Production~~Factors[2]

~~Onshore Petroleum and Natural Gas Production~~Component	Emission Factor[g] (scf/hour/component)
~~**Western US Population Emission Factors for all Components, Gas Service[a]**~~	
Valve	0.121
Connector	0.017
Open-ended Line	0.031
Pressure Relief Valve	0.193
Low Continuous Bleed Pneumatic Device Vents[b]	1.39
High Continuous Bleed Pneumatic Device Vents[b]	37.3
Intermittent Bleed Pneumatic Device Vents[b]	13.5
Pneumatic pumps[c]	13.3
~~**Population Emission Factors – All Components, Light Crude Service[d]**~~	
~~Valve~~	~~0.05~~
~~Flange~~	~~0.003~~
~~Connector~~	~~0.007~~
~~Open-Ended Line~~	~~0.05~~
~~Pump~~	~~0.01~~
~~Other[e]~~	~~0.30~~
~~**Population Emission Factors – All Components, Heavy Crude Service[f]**~~	
~~Valve~~	~~0.0005~~
~~Flange~~	~~0.0009~~
~~Connector (~~Other~~)~~	0.~~0003~~30
~~Open-Ended Line~~	~~0.006~~
~~Other[5]~~	~~0.003~~

~~[a] For multi-phase flow that includes gas, us`e the gas service emission factors.~~
~~[b] Emission factor is in units of "scf/hour/device."~~
~~[c] Emission Factor is in units of "scf/hour/pump."~~
~~[d] Hydrocarbon liquids greater than or equal to 20°API are considered "light crude."~~
~~[e] "Other" category includes instruments, loading arms, pressure relief valves, stuffing boxes, compressor seals, dump lever arms, and vents.~~
~~[f] Hydrocarbon liquids less than 20°API are considered "heavy crude."~~
~~[g] If the CO_2 volume percent in the gaseous stream flowing through the equipment is ≤ 80%, the emissions factors in Table E4 may be adjusted by multiplying them with the CO_2 volume percent.~~

Table E5. Default Average Component ~~Counts for Major Crude Oil Production Equipment~~Counts[2]

~~Major~~ Equipment	Valves		Connectors	Open-Ended Lines	~~Other Components~~Pressure Relief Valves
~~Wellhead~~	~~5~~	~~10~~	~~4~~	~~0~~	~~1~~
~~Separator~~	~~6~~	~~12~~	~~10~~	~~0~~	~~0~~
~~Heater-Treater~~	~~8~~	~~12~~	~~20~~	~~0~~	~~0~~
~~Header~~	~~5~~	~~10~~	~~4~~	~~0~~	~~0~~

~~**Table E6.** Default Average Component Counts for Major Onshore Natural Gas Production Equipment~~

~~Major Equipment~~	~~Valves~~	~~Connectors~~	~~Open-Ended Lines~~	~~Pressure Relief Valves~~
Wellheads	11	36	1	0
Separators	34	106	6	2
Meters/Piping	14	51	1	1
Compressors	73	179	3	4
In-Line Heaters	14	65	2	1
Dehydrators	24	90	2	2

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Appendix F. Emissions from CO_2 Entrained in Produced Oil and Gas

(a) Annual CO_2 Fugitive Emissions Entrained in Produced Oil and Gas[14]

$$CO_{2_{entrained}} = (V_{gas} \times \%CO_{2_{gas}} \times \rho CO_2 \times 0.001) + (M_{water} \times F_{CO2-water}) + (M_{oil} \times F_{CO2-oil}) \quad \text{(F.1)}$$

Where:

~~$CO_{2_{entrained}}$ = Emissions or other losses of CO_2 entrained or dissolved in crude oil/other hydrocarbons, produced water and natural gas that have been separated from the produced CO_2 for sale or disposal. Calculated based on quantities of crude oil, water and gas produced and the CO_2 content of each product (MT CO_2/year).~~

~~V_{gas} = Volume of natural gas or fuel gas, produced from the formation that CO_2 is being injected into, that is sold to third parties or input into a natural gas pipeline in year y (m^3/year), measured at standard conditions.~~

~~ρCO_2 = Density of CO_2 at standard conditions (1.899 kg/m^3 or 0.0538 kg/ft^3).~~

~~$\%CO_{2_{gas}}$ = % CO_2 in the natural gas or fuel gas that is sold to third parties or input into a natural gas pipeline, in year y (% volume).~~

~~M_{water} = Mass of water produced from the formation that CO_2 is being injected into, that is disposed of or otherwise not re-injected back into the formation (MT/year).~~

~~$F_{CO2-water}$ = Mass fraction of CO_2 in the water produced from the formation.~~

~~M_{oil} = Mass of crude oil and other hydrocarbons produced from the formation that CO_2 is being injected into (MT/year).~~

~~$F_{CO2-oil}$ = Mass fraction of CO_2 in the crude oil and other hydrocarbons produced from the formation (MT/year).~~

$\underline{CO_{2\ entrained}}$ = Emissions or other losses of CO_2 entrained or dissolved in crude oil/other hydrocarbons, produced water and natural gas that have been separated from the produced CO_2 for sale or disposal. Calculated based on quantities of crude oil, water and gas produced and the CO_2 content of each product (MT CO_2/year or MT CO_2/quarter).

$\underline{V_{gas}}$ = Volume of natural gas or fuel gas, produced from the formation that CO_2 is being injected

[14] The American Carbon Registry "Methodology for Greenhouse Gas Emission Reductions from Carbon Capture and Storage Projects," Version 1 (2015). Available at http://americancarbonregistry.org/carbon-accounting/standards-methodologies/carbon-capture-and-storage-in-oil-and-gas-reservoirs/acr-ccs-methodology-v1-0-final.pdf.

		into, that is sold to third parties or input into a natural gas pipeline in the reporting timeframe (m^3/year or m^3/quarter), measured at standard conditions.
ρCO_2	=	Density of CO_2 at standard conditions (1.899 kg/m^3 or 0.0538 kg/ft^3).
$\%CO_{2\,gas}$	=	% CO_2 in the natural gas or fuel gas that is sold to third parties or input into a natural gas pipeline in the reporting timeframe (% volume).
M_{water}	=	Mass of water produced from the formation that CO_2 is being injected into, that is disposed of or otherwise not re-injected back into the formation (MT/year or MT/quarter)
$F_{CO2\text{-}water}$	=	Mass fraction of CO_2 in the water produced from the formation.
M_{oil}	=	Mass of crude oil and other hydrocarbons produced from the formation that CO_2 is being injected into (MT/year or MT/quarter).
$F_{CO2\text{-}oil}$	=	Mass fraction of CO_2 in the crude oil and other hydrocarbons produced from the formation.

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Appendix G. Determination of a CCS Project's Risk Rating for Determining its Contribution to the LCFS Buffer Account

A percentage of a CCS project's LCFS credits must be contributed to the LCFS Buffer Account pursuant to the Regulation. The specific percentage of the contribution is determined by a CCS project's risk rating, based on the potential for CO_2 leakage associated with different types of risks and project-specific circumstances.

(a) The CCS Project Operator is required to determine the project's invalidation risk rating prior to submitting their application for CCS project certification, and to recalculate it every time the CCS project undergoes verification.

(b) When estimated risk values and associated mitigation measures are updated, any adjustments to the invalidation risk ratings will affect only the current and future year contributions to the Buffer Account.

(c) Factors that contribute to CCS project risk rating are classified into the categories identified in Table G1.

(d) The CCS project risk rating must be determined using the tables and methods in this appendix. The CCS Project Operator must determine the contribution to the invalidation risk rating for each risk type in Table G1.

Table G.1. CCS project contribution to CCS project risk rating based on risk types

Risk type	**Risk category**	**Risk Rating Contribution**
Financial	*Low Financial Risk:* CCS project operators that demonstrate their company has: • a Moody's rating of A or better; or • an equivalent rating from Standard & Poor's, and Fitch	0%
	Medium Financial Risk: CCS project operators that demonstrate their company has: • a Moody's rating of B or better meets; or • an equivalent rating from Standard & Poor's, and Fitch	1%
	High Financial Risk: CCS project operators that cannot make one of the two demonstrations above	2%

Social	*Low Social Risk:* CCS projects located in countries or regions ranked among the top 20th percentile based on the World Justice Project Rule of Law Index	0%
	Medium Social Risk: CCS projects located in countries or regions ranked between the 20th and 50th percentile based on the World Justice Project Rule of Law Index	1%
	High Social Risk: CCS projects located in countries or regions that are not ranked, or are ranked below the 50th percentile based on the World Justice Project Rule of Law Index	3%
Management	*Low Management Risk:* Demonstrated surface facility access control, e.g., injection site is fenced and well protected	1%
	Higher Management Risk: Poor or no surface facility access control, e.g., injection site is open, or not fenced or protected	2%
Site	*Low Site Risk:* Selected site has more than two good quality confining layers above the sequestration zone and a dissipation interval below the sequestration zone	1%
	Higher Site Risk: Selected site meets the minimum site selection criteria but does not meet the above site criteria	2%
Well integrity	*Low Well Integrity Risk:* All wells for the CCS project meet USEPA class VI well or equivalent requirements	1%
	Higher Well Integrity Risk: The CCS project has wells that do not meet USEPA class VI well or equivalent requirements	3%

(e) A Project Operator must use Table G2 to summarize and report to CARB the CCS project's risk rating and contribution to the Buffer Account for each risk type.

Table G.2. CCS Project Contribution to the Buffer Account for Each Risk Type

Risk type	**Risk category**	**Risk Rating Contribution**
Financial	☐ Low Financial Risk ☐ Medium Financial Risk ☐ High Financial Risk	

Social	☐ Low Social Risk ☐ Medium Social Risk ☐ High Social Risk	
Management	☐ Low Management Risk ☐ Higher Management Risk	
Site	☐ Low Site Risk ☐ Higher Site Risk	
Well integrity	☐ Low Well integrity Risk ☐ Higher Well integrity Risk	

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

$$CCS\ Project\ Risk\ Rating = 105\% - \left[(100\% - Risk_{Financial}) \times (100\% - Risk_{Social}) \times (100\% - Risk_{Management}) \times (100\% - Risk_{Site}) \times (100\% - Risk_{Well\ Integrity})\right] \quad \text{(G.1)}$$