

UPDATED UNDERGROUND INJECTION CONTROL REGULATIONS

FINAL TEXT OF REGULATIONS

CALIFORNIA CODE OF REGULATIONS, TITLE 14 DIVISION 2. DEPARTMENT OF CONSERVATION CHAPTER 4. DEVELOPMENT, REGULATION, AND CONSERVATION OF OIL AND GAS RESOURCES

Subchapter 1. Onshore Well Regulations

Article 2. Definitions

1720.1. Definitions

The following definitions are applicable to this subchapter:

(a) “Area of review” means an area around each injection well that is part of an underground injection project. The area of review shall be proposed by the operator as part of an underground injection project application or review, but may be specified by the Division depending on project-specific data and any other factors determined by the Division to ensure that the area of review is at least as broad as the area of influence.

The area of review is either:

(1) The calculated lateral distance encompassing within and beyond the intended injection zone to which the pressures or temperatures in the intended injection zone may cause the migration of the injection fluid or the reservoir fluid; or

(2) A fixed one-quarter-mile radius.

(b) “Cyclic steam injection well” means an injection well that injects steam into an underground formation and then subsequently produces hydrocarbons.

(c) “Disposal injection well” means an injection well into which fluid is injected primarily for purposes of disposal rather than enhancing the recovery of hydrocarbons.

(d) “Fluid” means any material or substance which flows or moves, whether semisolid, liquid, gas, or steam.

(e) “Freshwater” means water that contains 3,000 mg/L TDS or less.

(f) "Injection well" means a well into which fluids are being injected as part of an underground injection project, or that is approved by the Division for such purpose. A gas storage well, as defined in Section 1726.1(a)(4), is not an injection well.

(g) "Injection zone" means the defined three-dimensional space with fixed boundaries where fluid injected by an underground injection project is anticipated to occupy or otherwise be located. The injection zone may include more than one formation or strata.

(h) "Low-energy seep" means a surface expression for which the operator has demonstrated all of the following to the Division:

- (1) The fluid coming to the surface is low-energy and low-temperature;
- (2) The fluid coming to the surface is not injected fluid; and
- (3) The fluid coming to the surface is contained and monitored in a manner that prevents damage to life, health, property, and natural resources.

(i) "Low-use cyclic steam injection well" means a cyclic steam injection well that meets all of the following criteria:

- (1) In the past five calendar years, the well has not had more than 24 days of injection in a calendar year;
- (2) In the past five calendar years, the well has not had a volume of more than 12,000 barrels of injection in a calendar year; and
- (3) The well is not part of an underground injection project that has been known to cause surface expressions, as described in Section 1724.11(b).

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

(k) "Mg/L TDS" means milligrams per liter of total dissolved solids content.

(l) "Project Approval Letter" means the written record by which the Division documents its approval of an underground injection project, including any specific conditions applicable to the approval of that underground injection project.

(m) "Steamflood injection well" means an injection well that injects steam into an underground formation for purposes of enhancing the hydrocarbon recovery of other producing wells.

(n) "Surface expression" means a flow, movement, or release from the subsurface to the surface of fluid or other material such as oil, water, steam, gas, formation solids,

formation debris, material, or any combination thereof, that is outside of a wellbore and that appears to be caused by injection operations.

(o) "Surface expression containment measure" means an engineered measure to contain or collect the fluids or materials from a surface expression, including but not limited to, subsurface collection systems, collection wells, cisterns, culverts, French drains, collection boxes, earthen ditches, containment berms, or gas hoods or other gas collection systems.

(p) "Underground injection project" means sustained or recurring injection into one or more wells over an extended period into an approved injection zone for the purpose of enhanced oil recovery, disposal, storage of liquid hydrocarbons, pressure maintenance, or subsidence mitigation. Examples of underground injection projects include, but are not limited to, waterflood injection, steamflood injection, cyclic steam injection, carbon dioxide enhanced oil recovery, and disposal injection. An underground gas storage project, as defined in Section 1726.1(a)(6), is not an underground injection project.

(q) "Underground source of drinking water" or "USDW" means an aquifer or its portion which has not been approved by the United States Environmental Protection Agency as an exempted aquifer pursuant to the Code of Federal Regulations, title 40, section 144.7, and which:

(1) Supplies a public water system, as defined in Health and Safety Code section 116275; or

(2) Contains a sufficient quantity of groundwater to supply a public water system, as defined in Health and Safety Code section 116275; and

(A) Currently supplies drinking water for human consumption; or

(B) Contains fewer than 10,000 mg/L TDS.

(r) "Water source well" means a well drilled within or adjacent to an oil or gas pool for the purpose of obtaining water to be used in production stimulation or repressuring operations.

(s) "Water supply well" means a well that provides water for domestic, municipal, industrial, or irrigation purposes, but does not include a water source well.

(t) "Waterflood injection well" means an injection well that injects water or water-based liquid into an underground formation for purposes of enhancing the hydrocarbon recovery of producing wells.

Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, Public Resources Code.

Article 4. Underground Injection Control

1724.5. Purpose, Scope, and Applicability

The purpose of this article is to set forth regulations governing underground injection projects and injection wells. This article applies to underground injection projects and injection wells in existence prior to the effective date of this article, as well as new underground injection projects and injection wells. Underground injection projects and injection wells are not subject to the requirements of Article 5, Sections 1726 through 1726.10.

Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, Public Resources Code.

1724.6. Approval of Underground Injection Projects

(a) Operators shall obtain a Project Approval Letter from the Division for each underground injection project before any injection occurs as part of the underground injection project. The operator requesting approval for such a project must provide the appropriate Division district deputy with the data specified in Section 1724.7 and any data that, in the judgment of the Division, are pertinent and necessary for the proper evaluation of the project. When reviewing a proposal for a new underground injection project, the Division will consult with the State Water Resources Control Board or the Regional Water Quality Control Board.

(b) The Project Approval Letter shall specify the location and nature of the underground injection project, as well as the conditions of the Division's approval. The Project Approval Letter shall include identification of the approved injection zone for the underground injection project, and the approved injection zone shall not include a USDW. The Division may specify a limited duration of approval for an underground injection project in the Project Approval Letter. All underground injection projects shall

be operated in accordance with the requirements of this subchapter and the terms and conditions of the current Project Approval Letter.

(c) Any subsequent modification of an underground injection project requires the prior approval of the Division and shall be memorialized in either an addendum to the Project Approval Letter or a revised Project Approval Letter.

(d) The Division will review existing underground injection projects periodically, but not less than once every three years, to verify compliance with the requirements of this subchapter and the terms and conditions of the Project Approval Letter, and will periodically review the terms and conditions of the Project Approval Letter to ensure that they are effectively preventing damage to life, health, property, and natural resources. Project Approval Letters are subject to suspension, modification, or rescission by the Division.

(e) If the Division determines that the operation of an underground injection project is inconsistent with this subchapter or the terms and conditions of a current Project Approval Letter, or otherwise poses a threat to life, health, property, or natural resources, then upon written notice from the Division injection operations shall cease immediately, or as soon as it is safe to do so. Underground injection projects or injection operations suspended upon written notice from the Division or for any of the reasons specified under Section 1724.13 shall not resume without subsequent written approval from the Division.

(f) Within 60 days after transfer of an underground injection project to a new operator, the new operator shall meet with Division staff to ensure a complete understanding of the applicable requirements and terms and conditions of the Project Approval Letter.

Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, Public Resources Code.

1724.7. Project Data Requirements

(a) An underground injection project shall be supported by data filed with the Division that demonstrates to the Division's satisfaction that injected fluid will be confined to the approved injection zone and that the underground injection project will not cause damage to life, health, property, or natural resources. The engineering study, geologic study, and injection plan described in subdivisions (a)(1) through (a)(3) shall

demonstrate to the Division's satisfaction that injected fluid will not migrate out of the approved injection zone through another well, geologic structure, fault, fracture, fissure, hole in the casing, or other pathway, considering project duration, volume of fluid to be injected, and other relevant factors. The operator is responsible for ensuring that the data are current and accurately reflect the project setting and operation throughout the operating life of the project. The data filed with the Division shall include, at a minimum:

(1) An engineering study, including but not limited to:

(A) A description of how the area of review was determined, including calculations, variables, citations, and assumptions.

(B) A map of the area of review showing the location of the following:

(i) All wells within and adjacent to the boundary of the area of review;

(ii) All water supply wells that are within the area of review and identified in public records or otherwise known to the operator;

(iii) Any underground disposal horizons, mining, and other subsurface industrial activities not associated with oil and gas production within the area of review, to the extent such information is publicly available or otherwise known to the operator; and

(iv) Traces of the geologic cross sections provided under subdivision (a)(2)(E).

(C) A compendium of the following information:

(i) For all wells depicted in subdivision (a)(1)(B) (including water supply wells to the extent information is known or publicly available), the API numbers, or other identifying information for wells that do not have API numbers, and the wellbore paths, total depths, and depths of completion interval(s) of the wells;

(ii) The type and status of water supply wells depicted in subdivision (a)(1)(B); and

(iii) All data specified in Section 1724.7.1, provided in the form of graphical casing diagrams or flat-file data sets, for all wells that are within the area of review and that are completed in or penetrating the injection zone for the underground injection project or a deeper zone, including directionally drilled wells that intersect the area of review in the injection zone or a deeper zone.

(D) The planned well-drilling and plugging-and-abandonment program to complete the project, including a flood-pattern map, if applicable, showing all injection, production, and plugged and abandoned wells, and unit boundaries.

(2) A geologic study, including but not limited to:

(A) Reservoir characteristics of the injection zone, such as porosity, permeability, average thickness, areal extent, fracture gradient, original and present temperature and

pressure, and original and residual oil, gas, and water saturations. The scope of the geologic characterization shall encompass the caprock and sealing mechanisms, the injection zone including the vertical interval above and below the approved injection zone, and the areas where potential migration of fluid or entrapment of migrated fluid could occur.

(B) Reservoir fluid data for the injection zone, such as oil gravity and viscosity, water quality, presence and concentration of non-hydrocarbon components in the associated gas (such as hydrogen sulfide), and specific gravity of gas. Liquid analysis of the reservoir fluid shall be performed in accordance with Section 1724.7.2.

(C) Structural contour map drawn on a geologic marker at or near the top and base of each injection zone in the area of review, indicating faults and any lateral containment features. If faults are identified, the operator must address whether or not the faults are capable of confining fluid to the approved injection zone, and any geologic features that could result in the migration of fluid out of the approved injection zone.

(D) Isopach map of each injection zone or subzone in the area of review.

(E) At least two geologic cross sections in the area of review through at least three wells, including one injection well. As near as possible, one of the geologic cross sections shall be along strike and the other geologic cross section shall be perpendicular to strike. The cross sections shall extend from the base of the deepest production or injection zone to surface and indicate the location of the approved injection zone, the base of freshwater, and the base of the USDW.

(F) Representative electric log to a depth below the deepest producing or injection zone, whichever is deeper, identifying all geologic units, formations, USDWs, freshwater aquifers, and oil or gas zones. The electric log shall identify the API number of the well that was logged.

(3) An injection plan, including but not limited to:

(A) Statement of primary purpose of the project.

(B) A map showing injection facilities related to the project, and piping and instrumentation diagram(s) for the injection facilities.

(C) Statement of the anticipated project duration, anticipated daily rate of injection, (by well), and anticipated cumulative net volume of fluid to be injected.

(D) Identification of all wells that are part of the underground injection project, including injection wells, affected production wells, water source wells, observation or

other wells, and any planned wells to the extent known. The depths of water source wells shall also be provided.

(E) Monitoring system—~~er~~, including methods or standard operating procedures to be utilized to ensure that no damage is occurring and that the injection fluid is confined to the approved injection zone. In the event the Division, the State Water Resources Control Board, or the Regional Water Quality Control Board requires groundwater monitoring in relation to the underground injection project, or as a condition of project approval, the operator shall consult with the State Water Resources Control Board or the Regional Water Quality Control Board and provide the Division with documentation and the results of such consultation.

(F) Method of injection, including such information as injection string configuration and bottom-hole assembly.

(G) List of cathodic protection or other corrosion prevention measures employed for plant, lines, and wells, if such measures are warranted.

(H) Identification of the source(s) of the injection liquid and an analysis of the injection liquid, in accordance with Section 1724.7.2.

(4) All data supporting the determination under Section 1724.10.3 of the maximum allowable surface injection pressure for each injection well in the underground injection project, including all calculations, variables, citations, and assumptions.

(5) Copies of letters of notification sent to offset operators.

(6) Any other data that, in the judgment of the Division, are pertinent and necessary for the proper evaluation of the underground injection project. Examples of such data are: isogor maps, water-oil ratio maps, isobar maps, three-dimensional geologic models, reservoir simulation results, isopach maps of the confining layers, equipment diagrams, and safety programs.

(b) The addition of an injection well to an underground injection project is subject to approval by the Division, and shall be indicated in a summary list of approved injection wells associated with the underground injection project, which shall be referenced by the Project Approval Letter for the underground injection project. When an injection well is added to an underground injection project, the operator shall provide the Division with a brief description of how the injection well will impact the underground injection project, any data relevant to the addition of the injection well, and an update to the data previously provided to the Division if relevant conditions have changed or if more accurate data have become available. The addition of an injection well does not require

the operator to submit data previously provided to the Division.

(c) All data required under this section shall be submitted to the Division digitally. If requested by the Division, a hard copy of specified data shall also be submitted. All maps, diagrams, and exhibits required in subdivision (a) shall be clearly and appropriately labeled, such as to title, scale, and purpose, and shall clearly identify wells, boundaries, zones, contacts, and other relevant data.

(d) All data required under this section shall be submitted to the Division with a cover page including a statement that appropriate licensed professionals, whose signatures and stamps appear at the bottom of the page, are responsible for all data, if any, subject to the requirements of Business and Professions Code sections 6735, 7835, or 7835.1. If the operator determines that the submission does not include material subject to the requirements of Business and Professions Code sections 6735, 7835, or 7835.1, the cover page shall so indicate, and shall provide the name(s) and signature(s) of the individual(s) responsible for preparing the submission.

(e) The Division may accept data alternative to what is required under subdivision (a), provided that the operator demonstrates to the Division's satisfaction all of the following:

(1) It would be an unreasonable burden to provide the data specified in subdivision (a);

(2) The alternative data provided by the operator accomplishes the same purpose as the data it would replace;

(3) The underground injection project is, on whole, supported by data demonstrating that injected fluid will be confined to the approved injection zone, and that the underground injection project conforms to the requirements of this subchapter and will not cause damage to life, health, property, or natural resources.

Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, Public Resources Code.

1724.7.1. Casing Diagrams

(a) Casing diagrams submitted under the requirements of this article shall include all of the following data:

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

(2) Date the well was spudded;

- (3) Ground elevation from sea level;
 - (4) Reference elevation (i.e., rig floor or Kelly bushing);
 - (5) Base of freshwater;
 - (6) Base of the lowermost USDW penetrated by the well;
 - (7) Sizes, grades, connection type, and weights of casing;
 - (8) Depths of shoes, stubs, and liner tops;
 - (9) Depths of perforations and perforation intervals, open-hole completions, water shutoff holes, cement ports, cavity shots, cuts, type and extent of casing damage, type and extent of junk or fish, and any other feature that influences flow in the well or may compromise the mechanical integrity of the well;
 - (10) Information regarding equipment in the well such as subsurface safety valves, packers, and gas lift mandrels;
 - (11) Diameter and depth of hole for all drilled intervals;
 - (12) Identification of cement plugs inside casings, including locations of the top and bottom of cement plugs;
 - (13) Identification of cement fill behind casings, including locations of the top and bottom of cement fill;
 - (14) Type and weight (density) of fluid between cement plugs; and
 - (15) Depths and names of the formations, zones, and markers penetrated by the well, including the top and bottom of both the injection zone and confining layer(s) for the underground injection project(s).
- (b) Each casing diagram submitted to the Division shall be accompanied by documentation of the following:
- (1) All steps of cement yield and cement calculations performed;
 - (2) 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
 - (3) The wellbore path, providing measured depth and both inclination and azimuth measurements.
- (c) When multiple boreholes are drilled in a well, all of the information listed in this section is required for both the original hole and for any subsequent redrilled or sidetracked wellbores.
- (d) Measured depth and true vertical depth shall be provided for all depths required under subdivision (a).

(e) Operators may satisfy the requirements of section 1724.7(a)(1)(C)(iii) by submitting graphical casing diagrams or a flat-file data set containing all of the information described in this section.

Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, Public Resources Code.

1724.7.2. Liquid Analysis

(a) Liquid analysis required under this article shall include testing for all of the following: total dissolved solids; total petroleum hydrocarbon as crude oil; major cations (Ca, Mg, Na, K, Fe, Mn, Sr, B); major anions (Cl, SO₄, HCO₃, CO₃, Br, I); total alkalinity and hydroxide; electrical conductance; pH; and temperature.

(b) The Division may require testing for additional constituents on a project-specific basis. Any additional constituents shall be listed in the Project Approval Letter for the project.

(c) To ensure the liquid analysis required under Section 1724.7(a)(2)(B) is representative of the reservoir liquid in its native condition, if feasible the liquid analyzed shall be either sampled from the injection zone itself prior to commencement of any injection into the reservoir or sampled from an analogous reservoir that has not already received injection fluid. The representative sample shall be recovered after all completion and drilling fluid has been circulated from the wellbore.

(d) To ensure the liquid analysis required under Sections 1724.7(a)(3)(H) and 1724.10(d) is representative of the liquid actually injected, the liquid to be analyzed shall be sampled after all additives (if any) are added to the liquid, and after all treatment or separation processes (if any).

(e) Liquid analysis required under this article shall be performed by a laboratory that is certified by the State Water Resources Control Board environmental laboratory accreditation program. The performing laboratory shall submit the data and analysis to the Division directly, using a digital format.

Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, Public Resources Code.

1724.8 Evaluation of Wells Within the Area of Review

(a) An underground injection project shall not cause or contribute to the migration of fluid outside the approved injection zone, or otherwise have an adverse effect on the underground injection project or cause damage to life, health, property, or natural resources. The following requirements apply, at minimum and subject to augmentation by the Division on a project-specific basis, to ensure that wells within the area of review will not be a potential conduit for fluid migration outside the approved injection zone:

(1) All wells within the area of review that penetrate the injection zone for the underground injection project or a deeper zone, including directionally drilled wells that intersect the area of review in the injection zone or a deeper zone, shall be evaluated for the potential to allow fluid to migrate outside of the approved injection zone. The Division's evaluation for the potential for a well to allow fluid migration will include evaluation of the cementing records. Where cementing records are inadequate or unreliable, the Division may require a cement evaluation log. The operator should identify, and the Division confirm, wells which may require integrity testing, well logging, or monitoring in order to provide the requisite assurances that such wells will not act as conduits for fluid migration. The Division may require wells be examined, remediated, plugged and abandoned, or monitored as a condition of approval for an underground injection project if the Division is concerned that the well has the potential to allow fluid to migrate outside of the approved injection zone.

(2) Plugged and abandoned wells within the area of review shall have cement as specified in Section 1723.1. The Division may require plugged and abandoned wells be re-entered, examined, re-plugged and abandoned, or monitored as a condition of approval for an underground injection project if the Division is concerned that the well has the potential to allow fluid to migrate outside of the approved injection zone.

(3) If a plugged and abandoned well within the area of review does not meet the plugging specifications of subdivision (a)(2), the Division may approve an alternative demonstration that the well will not be a potential conduit for fluid migration outside the approved injection zone. The Division's approval of such an alternative demonstration shall be supported by written findings by the Division that identify each plugged and abandoned well in the area of review that does not meet the cement specification of subdivision (a)(2), specify how the well(s) do not meet the requirements of subdivision (a)(2), and identify the bases for the Division's approval of the alternative demonstration.

Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, Public Resources Code.

1724.10. Filing, Notification, Operating, and Testing Requirements for Underground Injection Projects

(a) The appropriate Division district deputy shall be notified of any anticipated changes in an underground injection project resulting in inconsistency with the current conditions of approval, such as: expansion of the project, change of injection interval, or increase in maximum allowable surface injection pressure. Such changes shall not be carried out without prior written approval of the Division in accordance with Section 1724.6.

(b) In addition to the notice of intention that may be required under Public Resources Code section 3203, any addition of an injection well to an underground injection project, including the conversion of a well without alteration of casing, requires the prior written approval of the Division in accordance with Section 1724.6. The operator shall notify the Division and conduct testing as required under Section 1724.10.1 if the packer or tubing in an injection well is set, reset, moved, or changed.

(c) An injection report on a current Division form or in a digital format acceptable to the Division shall be filed with the Division on or before the last day of each month, for the preceding month.

(d) A representative chemical analysis of the liquid being injected, as specified in Section 1724.7.2, shall be made and filed with the Division whenever the source of injection liquid is changed, or as requested by the Division. For the purposes of this subdivision, the source of injection is changed if a contributing source is added to or removed from the injection liquid, or if there is a significant change to the relative contribution of individual sources such that the last chemical analysis is not representative of the liquid being injected.

(e) For each underground injection project that includes an injection well with open perforations located within 500 linear feet of the screen or perforations of a water supply well, the operator shall provide to the Division in digital format on a yearly basis all of the information listed in subdivisions (e)(1) through (e)(4). On a project-specific or well-specific basis, the Division may specify a distance greater than 500 feet as the distance that triggers the requirements of this subdivision if, in the Division's judgment, geological

conditions or the relative location of any water supply well warrants the additional data collection listed in subdivisions (e)(1) through (4). The applicability of this subdivision shall be based on a diligent search by the operator, including consultation of public records, and is not triggered by water source wells. When applicable, the following information shall be provided:

(1) A water treatment process flow diagram depicting all physical and chemical treatment processes applied to the injection fluid, from its source to the injection well;

(2) The safety data sheet for each chemical additive emplaced in injection wells within the underground injection project, and for each chemical added to the fluid to be injected from the time the fluid is first obtained to the time it is injected;

(3) The project-aggregate volume or weight of each additive reported under subdivision (e)(2); and

(4) A brief description of the intended purpose of each additive reported under subdivision (e)(2).

(f) All injection piping, valves, and facilities shall meet or exceed design standards for the maximum allowable injection pressure or the maximum pressure the equipment will be subjected to, and shall be maintained in a safe and leak-free condition.

(g) Except as provided in this subdivision below, all injection wells shall be equipped with tubing and packer, with the packer isolating the injection zone set no more than 100 feet above the approved injection zone. The packer shall not be set below open perforations if the packer is set within the approved zone of injection. The operator may use a technical equivalent of a packer instead of a packer, provided that the Division has approved the alternative as an effective means to isolate the production tubing from the casing. Injection wells equipped with tubing and packer may inject through the tubing, but not through the casing-tubing annulus unless the operator has written approval from the Division. Tubing and packer are not required for the following:

(1) Steamflood and cyclic steam injection wells;

(2) Any injection well that the Division approves for operation without tubing and packer and for which the operator demonstrates based on documented evidence, that:

(A) The well does not penetrate any USDW;

(B) The well is completed with more than one string of casing cemented to the satisfaction of the Division below the base of the lowermost USDW penetrated by the well; or

(C) There is other justification for a determination that all USDW, hydrocarbon, and anomalous zones can be protected without the use of tubing and packer.

(3) An injection well that was not required to be equipped with tubing and packer prior to April 1, 2019, is not subject to the requirements of this subdivision until April 1, 2021.

(h) Surface injection pressure of an injection well shall not exceed the maximum allowable surface pressure, as determined under Section 1724.10.3.

(i) Mechanical integrity testing must be performed on all injection wells to ensure the injected fluid is confined to the approved injection zone. Mechanical integrity testing shall consist of a two-part demonstration in accordance with Sections 1724.10.1 and 1724.10.2.

(1) The operator shall notify the appropriate Division district office at least 48 hours before performing any testing under Sections 1724.10.1 and 1724.10.2 so that Division staff may witness the operations, unless the Division approves shorter notice. This notification requirement also applies to subsequent schedule changes the operator may make for a previously noticed test.

(2) Digital copies of surveys and test results shall be submitted to the Division within 60 days of the tests.

(3) Injection wells shall be constructed and maintained to allow for compliance with the testing described in Sections 1724.10.1 and 1724.10.2.

(4) Any injection well, including a well not actively injecting, that is not tested as required under Sections 1724.10.1 and 1724.10.2 shall automatically lose approval to inject, and subsequent written approval from the Division is required to reinstate injection.

(5) If testing conducted under Sections 1724.10.1 or 1724.10.2 is not successful, then the operator shall undertake remedial work or conduct further testing as necessary to satisfy the Division that the well will not damage life, health, property, or natural resources. In some instances, plugging and abandonment of the well may be necessary to ensure that the well will not damage life, health, property, or natural resources. The necessary remedial work or testing shall be completed within 180 days, unless a longer timeframe is approved by the Division. The requirements of this subdivision are in addition to any other penalty or remedial requirement that may be imposed by the Division.

(j) Injection wells and related facilities shall be monitored, as specified in the Project Approval Letter for each underground injection control project, in order to allow for the discovery and correction of abnormal operating conditions.

(k) Operators of cyclic steam injection wells shall maintain records in machine-readable format of the number, dates, duration, and volume of fluid injected of each injection cycle performed on each cyclic steam injection well. Such records shall be maintained as long as the underground injection project is approved for injection, and shall be provided to the Division upon request.

(l) Additional requirements or modifications of the above requirements may be necessary to fit specific circumstances and types of projects. Examples of such additional requirements or modifications are:

(1) Injectivity tests.

(2) Graphs of time vs. oil, water, and gas production rates, maintained for each pool in the project and available for periodic inspection by Division personnel.

(3) Graphs of time vs. tubing pressure, casing pressure, and injection rate maintained for each injection well and available for periodic inspection by Division personnel.

(4) List of all observation wells used to monitor the project, indicating what parameters each well is monitoring (i.e., pressure, temperature, etc.), submitted to the Division annually.

(5) Isobaric maps of the injection zone, submitted to the Division annually.

(6) Notification of any change in waste disposal methods.

(7) Periodic land-surface elevation change measurements.

Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, Public Resources Code.

1724.10.1. Mechanical Integrity Testing Part One – Casing Integrity

(a) **Casing Pressure Test at the Maximum Allowable Surface Pressure.** Prior to commencing injection operations for the first time after a well is approved or reapproved by the Division for injection, each injection well shall pass a pressure test of the casing to determine the absence of leaks. Thereafter, the casing of each well shall be tested at least once every five years, prior to recommencing injection operations following the repositioning or replacement of downhole equipment, or whenever requested by the

Division. If an injection well is a gas disposal well, then the casing of the well shall be tested at least once every year. If a required pressure test is not successfully completed, then the operator shall immediately notify the Division and the well shall not be used for injection without subsequent written approval from the Division.

(b) Pressure testing under this section shall conform to the following:

(1) If injection in the well is through tubing and packer, then the pressure test shall be of the casing-tubing annulus of the well.

(2) Pressure testing shall be conducted with a liquid unless the Division approves pressure testing with gas.

(3) If pressure testing will be conducted with a liquid that contains additive other than brine, corrosion inhibitors, or biocides, then the operator shall consult with the Division regarding the contents of the liquid prior to commencing testing.

(4) The wellbore shall be filled with a stable column of fluid that is free of excess gases.

(5) Pressure tests shall be recorded and a calibrated gauge shall be used that can record a pressure with an accuracy within one percent of the testing pressure. Pressure shall be recorded at least once per minute during testing. If an analog gauge is used, then the test pressure shall be within the mid-range scale of the gauge. The pressure test results shall be submitted to the Division in a digital tabular format within 60 days of the date the test is conducted. The charts or digital recording of the pressures during testing shall be provided to the Division upon request.

(6) The operator may select the initial test pressure of the pressure test, provided that the pressure test is conducted at an initial test pressure of at least 200 psi above surface pressure, and the maximum allowable surface injection pressure for the injection well, as determined under Section 1724.10.3, shall not exceed the initial test pressure used during the most recent successful pressure test.

(7) Pressure tests shall test the casing of the well from the surface to a depth that is within 100 feet measured depth above the uppermost perforation, immediately above the casing shoe of the deepest cemented casing, or immediately above the top of the landed liner, whichever is highest. If the top of the landed liner is 100 feet or more above the cemented casing shoe, then the pressure test shall be to a depth specified by the Division on a case-by-case basis.

(8) A pressure test is successful if the pressure gauge does not show more than a three percent change from the initial test pressure over a continuous 30-minute period,

except that if the well is a cyclic steam injection well, then an increase in pressure of as much as 10 percent is a successful test.

(9) The Division may modify the testing parameters on a case-by-case basis if, in the Division's judgment, the modification is necessary to ensure an effective test of the integrity of the casing.

(c) **Alternative Pressure Monitoring.** Subject to the Division's approval, for injection wells equipped with tubing and packer, operators may propose a pressure testing and annular pressure monitoring program, consistent with this subdivision, as a substitute for the pressure test described in subdivision (a). If an injection well is covered by an approved pressure testing and annular pressure monitoring program, then the maximum allowable surface pressure for the well is the calculated pressure value under Section 1724.10.3(a)(1).

(1) An operator's proposals for alternative annular pressure monitoring shall include the following information:

(A) All relevant information about the injection wells proposed to be monitored, including identifying information, size of the tubing and packer and setting depth, and date of the last tubing and packer reset;

(B) All relevant information about the proposed pressure monitoring system, including monitoring instrumentation specifications, computer data acquisition and storage system specifications, method and frequency of calibrating and otherwise confirming the working order of the monitoring system, data retention, and reporting protocols with a clear identification of reportable statistical deviations;

(C) Schedule of injection project implementation, including the known and anticipated addition or removal of wells from the project; and

(D) Technical justifications and reasons for requesting the alternative proposal.

(2) Alternative pressure testing and annular pressure monitoring programs are subject to the Division's approval, and the requirements and limitations stated in subdivisions (A) through (F), below.

(A) The well shall be pressure tested in accordance with all of the requirements in subdivision (a), except that pressure tests shall be conducted at an initial pressure of at least 500 psi, and subdivision (a)(6) shall not apply.

(B) In order to demonstrate ongoing mechanical integrity, the alternative annular pressure monitoring program shall adhere to the following conditions:

(i) The casing-tubing annulus shall have a minimum of 100 psi pressure at all times, preferably with a nitrogen gas blanket at the surface to stabilize potentially large variations in pressure due to thermal expansion of incompressible fluid;

(ii) There shall be an observable pressure differential (+/- 10 percent of the tubing pressure or at least +/- 50 psi) between the annular pressure and the tubing pressure; and

(iii) There shall be no anomalous variances in the annular pressure. If there are significant pressure variations from the historic daily pressure readings, these shall be satisfactorily explained and documented as part of the operator's record of mechanical integrity.

(C) The Division may consider proposals to modify the conditions of subdivision (c)(2)(B) on a case-by-case basis if the Division determines that the proposal will represent a stronger demonstration of ongoing mechanical integrity. Such proposals may include, but are not limited to, fail-safe systems, such as automatic casing pressure relief systems, and other back-up safety, shutdown, and pressure relief systems.

(D) The casing-tubing annular pressure shall be measured and recorded at least as frequently as every five minutes with a pressure gauge having an appropriate range. The record of such documentation shall be made available to the Division upon request, including in digital form within one business day of a request from the Division. A Division-approved, operating supervisory control and data acquisition (SCADA) system, with automatic computer alarm notification, may be used to satisfy this requirement and is a preferred methodology.

(E) The operator shall take immediate action to investigate any anomalous pressure incidents, as compared to historic daily readings. If there is any reason to suspect a leak, the operator shall take immediate action to prevent damage to public health, safety, and the environment. The operator shall provide immediate notice to the Division of any anomalous pressure incidents and the steps taken in response.

(F) At any time, the Division may request a full casing pressure test as described in subdivision (a).

(d) **Alternate Testing Methods.** An alternate mechanical integrity testing method may be used to satisfy the requirement under this section to pressure test the casing of an injection well if the alternate testing method has been approved by the Division on a case-by-case basis as being at least as effective as pressure testing to demonstrate the integrity of the well at the calculated pressure value under Section 1724.10.3(a)(1).

Examples of alternate testing methods that would be considered on a case-by-case basis are a casing wall thickness inspection to estimate internal and external corrosion, employing such methods as magnetic flux or ultrasonic technologies; or a combination of an ultrasonic imaging tool and a cement evaluation log. If the most recent successful test of an injection well under this section was by testing approved under this subdivision, then the maximum allowable surface pressure for the well is the calculated pressure value under Section 1724.10.3(a)(1).

(e) For injection wells that as of April 1, 2019, were approved for injection but were not previously subject to periodic casing pressure testing requirements, testing under this section is not required to be completed until April 1, 2024, unless the injection well is a gas disposal well, in which case testing shall be completed by April 1, 2020. For all other injection wells, if testing consistent with the requirements of this section has not been done on the well in the past five years, or in the past year if it is a gas disposal well, then the well shall not be used for injection without subsequent written approval from the Division.

Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, Public Resources Code.

1724.10.2 Mechanical Integrity Testing Part Two – Fluid Migration Behind Casing, Tubing, or Packer

(a) In addition to testing under Section 1724.10.1, operators shall periodically test injection wells to demonstrate that there is no fluid migration behind the casing, tubing, or packer. This testing may be accomplished by any of the methods set forth in subdivisions (d) through (f), or other method approved by the Division (including modifications of the methods below when approved by the Division in writing). Operators shall obtain written approval from the Division regarding the testing method prior to performing the tests.

(b) Testing under this section is required within three months after injection has commenced for the first time after a well is approved or reapproved by the Division for injection. Commencing April 1, 2019, subsequent testing under this section is required at least once every two years, with the following exceptions:

- (1) Disposal injection wells shall be tested at least once a year;

(2) Low-use cyclic steam injection wells are required to be tested at least once every five years;

(3) If a well that previously met the definition of a low-use cyclic steam injection well has not been tested in over one year, then testing is required within one year of the time that the well stopped being a low-use cyclic steam injection well.

(4) Steamflood injection wells equipped with tubing and packer are required to be tested at least once every five years;

(5) Testing is required following an unplanned variance in injection pressure of more than 25 percent within a 48-hour period, unless the operator demonstrates to the Division that the variance was the result of an issue that does not relate to well integrity; and

(6) Testing is required when requested by the Division, including as may be specified in the Project Approval Letter.

(c) On a project or well-specific basis, the Division may approve different testing frequencies from those specified in subdivision (b), and may approve alternative methods for demonstrating an absence of fluid migration behind the casing, tubing, or packer. Any approved variance shall be documented in writing and be based on specific factors identified in the writing, including but not limited to well construction, age of the well, demonstrated quality of cement encasing the well, quality of groundwater in the area, and operational considerations.

(d) **Radioactive Tracer Survey.** In addition to all other applicable federal, state, and local requirements, a radioactive tracer survey performed to satisfy the requirements of this section shall adhere to the following:

(1) Testing shall be conducted while injecting, and the operator shall ensure that adequate fluid can be supplied for the test. The injection rate shall be governed by the ability of the operator to track the radioactive tracer as it moves downward, but the injection rate should be stable and as close to the normal operating injection rate as practical.

(2) If the injection well is equipped with a packer and there is no injection occurring through the casing-tubing annulus, the casing-tubing annulus valve shall be open during testing and there shall be no fluid flow, unless the well is a gas disposal well. If fluid flow is indicated, the test shall be discontinued and the casing-tubing annulus shall be evaluated.

(3) Gamma ray detector sensitivity shall be set in consideration of lithologic and other effects.

(4) Before conducting the test, a dynamic temperature survey shall be run from at least 200 feet above the packer to the total depth, and a static temperature survey shall be run for the entire length of the well. A casing collar locator shall be run from 200 feet above the packer to the total depth. If the well is not equipped with tubing and packer, then the casing collar locator shall be from 200 feet above the top perforation to the total depth.

(5) A background gamma ray log over the interval to be tested shall be recorded before any radioactive material is introduced into the well.

(6) Radioactive tracer tubing rate checks shall be run within 200 feet of the top and 200 feet from the bottom of the tubing.

(7) The release of a slug of radioactive material shall be above the interval to be tested.

(8) The slug of radioactive material shall be followed with the logging tool or the tool shall make repeated passes upward through the slug as it moves down the well. Alternatively, with Division approval, the amount for the slug to go from surface to the tool may be measured. All logging shall be done at a single logging speed which is appropriate for the injection rate to allow quantitative measurements of deflections to be evaluated.

(9) If repeated passes are used, the logs resulting from the slug-tracking exercise should overlap so that the return of radioactivity to the level which existed before the slug's passing is demonstrated for the entire length of the section of the well being tested. The logs of all passes shall be presented as a composite log on a common depth track. If means to differentiate the log traces are available, then no other presentation is required. If the traces cannot be differentiated on the composite log, then they shall also be presented individually.

(10) After any ejection of radioactive tracer into the wellbore, the slug of radioactive tracer material shall be followed until it has moved below the interval being tested. Any portion of the slug of radioactive tracer material that divides shall be accounted for.

(11) After completion of the log passes, a final log should be made through the entire tested interval to check for residual radioactivity which might be associated with exit of radioactive tracer material from the wellbore.

(12) If a well other than a steam injection well is injecting at a rate consistent with that described in subdivision (d)(1), radioactively treated beads shall be introduced into the well and evaluated according to subdivision (d)(7) through (d)(10).

(13) Steam injection wells shall be tested using an inert gas tracer.

(e) **Temperature Survey.** A temperature survey performed to satisfy the requirements of this section shall adhere to the following:

(1) The well shall be taken off injection at least 24 hours but not more than 48 hours prior to performing the temperature survey, unless an alternate duration has been approved by the Division.

(2) The temperature logging tool shall be calibrated to the manufacturer's recommendations or as otherwise requested by the Division.

(3) The well shall be logged from the surface downward, lowering the tool at a rate of no more than 30 feet per minute or a faster rate approved in advance by the Division based upon the operator's demonstration that the faster rate will yield data of at least equivalent quality.

(4) If the well has not been taken off injection for at least 24 hours before the log is run, comparison with either a second log run six hours after the time the log of record is started or a log from another well at the same site showing no anomalies shall be available to demonstrate normal patterns of temperature change.

(5) The log data shall be provided to the Division digitally in LAS, ASCII, or other format that is acceptable to the Division.

(f) **Noise Log.** For a noise log performed to satisfy the requirements of this section, logging shall include a repeat section of no less than 200 feet, preferably across intervals where anomalies are present.

(g) The operator shall take immediate action to investigate any anomalies encountered during testing required under this section. If there is any reason to suspect fluid migration, the operator shall take immediate action to prevent damage to public health, safety, and the environment, and shall notify the Division immediately.

Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, Public Resources Code.

1724.10.3. Maximum Allowable Surface Injection Pressure

(a) Injection pressure at surface shall not exceed the maximum allowable surface injection pressure for an injection well, as approved by the Division under this section and documented in the supporting project data under Section 1724.7(a)(4). Except as provided under subdivision (b), the maximum allowable surface injection pressure for an injection well shall be the lower of following two values:

(1) A calculated pressure value equal to the true vertical depth of the shallowest portion of the well open to the injection zone multiplied by the difference between the injection gradient and the injection fluid gradient ($MASIP = (IG - IFG) * TVD$). The injection gradient used for this calculation shall be the product of the fracture gradient as determined under subdivision (b) or (c), multiplied by 0.95, or other multiplier subject to Division approval on a well-specific basis that more appropriately accounts for factors such as a conservative allowance for friction loss. If the Division allows friction loss to be factored into the calculation, then the friction factor shall be calculated based on the new coated tubing of the largest diameter that will be used for injection. If a single well is injecting through dual injection strings, then the friction factor of the two strings shall be calculated separately.

(2) The initial test pressure used during the most recent successful pressure test of the injection well under Section 1724.10.1(b). If the pressure testing requirement for the injection well was satisfied under Section 1724.10.1(c) or (d), then the maximum allowable surface injection pressure shall be the calculated pressure value as determined under subdivision (a)(1).

(b) The Division may approve a maximum allowable surface injection pressure higher than what would be allowed under subdivision (a) based on a demonstration by the operator of all of the following:

(1) The higher maximum allowable surface injection pressure is needed for effective resource production;

(2) Injected fluid will remain confined to the approved injection zone;

(3) The higher pressure will not initiate fractures outside the approved injection zone or propagate existing fractures outside the approved injection zone; and

(4) The higher pressure will not otherwise threaten life, health, property, or natural resources.

(c) Subject to the Division's approval, an estimated baseline fracture gradient may be used for determining the maximum allowable surface injection pressure for all injection

wells within a given area. An estimated baseline fracture gradient shall be supported by representative step-rate tests, or other testing or geologic data, demonstrating to the Division's satisfaction that the estimated baseline fracture gradient is lower than the actual fracture gradient that would be encountered anywhere in the injection zone where the estimated baseline fracture gradient will be used.

(d) If an injection well is not within the area of an approved estimated baseline fracture gradient, or if the operator seeks to establish a well-specific fracture gradient above the estimated baseline fracture gradient, then the fracture gradient shall be determined by performing a step-rate test on the injection well or by another method approved by the Division to effectively determine the fracture gradient.

(e) Step-rate tests conducted to satisfy the requirements of this section shall meet the following requirements:

(1) Before commencing the test, the well shall be shut in until the bottom-hole pressures approximate shut-in formation pressures. If the shut-in well flows to the surface, then the static surface pressure shall be read and recorded.

(2) The operator may determine the appropriate length of time to conduct each step of the step-rate test, provided that each of the steps is conducted for the same amount of time and a stabilized pressure value is obtained within each step. If steps are conducted for differing lengths of time, if a step does not yield a stabilized pressure value, or if formation breakover is not clearly demonstrated, then the Division may deem the step-rate test inconclusive. Suggested step durations are 30 minutes if the formation has a permeability of more than 10 millidarcies, and sixty minutes if the formation has a permeability of ten millidarcies or less.

(3) The first three steps of the step-rate test shall be below the fracture gradient. Suggested step pressures are 5, 10, 20, 40, 60, 80, and then 100 percent of the proposed injection rate, or until formation breakdown.

(4) Real-time downhole and surface pressure recording using digital pressure gauges shall be employed, unless an alternative has been approved by the Division.

(5) Bottom-hole pressure shall be recorded at a zero injection rate for at least one full time step before the first step of the step-rate test and for one full time step after the last step of the step-rate test.

(6) Step-rate test data reported under Section 1724.7(a)(4) shall include the injection rate, bottom-hole pressure, surface pressure, pump rate, volume, and time recorded continuously at a rate of at least one pressure recording per second during the step-rate

test. The step-rate test data submitted to the Division shall be unaltered and submitted in a digital format.

(7) Operators shall provide the appropriate Division district office with at least 24 hours of advance notice, or other period of advance notice acceptable to the district office, prior to conducting a step-rate test for purposes of this section.

Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, Public Resources Code.

§ 1724.10.4. Continuous Pressure Monitoring

(a) Operators shall comply with the following requirements for well-specific injection pressure monitoring:

(1) Well-specific injection pressure shall be continuously recorded at all times that a well is approved for injection by the Division, regardless of whether injection is actually occurring. An operator may satisfy this requirement by recording injection pressure from a header or manifold if approved by the Division based on a showing that the operator is able to calculate well-specific injection pressures from the recorded data. An operator may suspend continuous injection pressure recording for a well while the well is disconnected from all injection lines.

(2) Injection pressure records shall be maintained by the operator as long as the well is approved for injection by the Division, and for three years after that, and shall be provided to the Division upon request.

(3) On or before the last day of each month, operators shall report to the Division the highest instantaneous injection pressure for each injection well in the last preceding calendar month.

(4) Digital or analog pressure recording devices may be used to meet the requirements of this subdivision. A Division-approved supervisory control and data acquisition (SCADA) or equivalent continuous real-time recording system, with automatic computer alarm notification, is not required but may be used to meet the requirements of this subdivision. Pressure recording devices shall be maintained in good working order and be calibrated as recommended by the manufacturer. Evidence of such calibration shall be available to the Division upon request.

(5) The Division may waive the requirements of this section for an injection well if the operator demonstrates that the injection facilities are configured in a manner that effectively prevents injection into the injection well above the maximum allowable surface injection pressure.

(b) Operators are not required to comply with subdivision (a) until April 1, 2021. Until an operator has complied with subdivision (a), the operator shall ensure that an accurate, operating pressure gauge or pressure recording device shall be available at all times, and all injection wells shall be equipped for installation and operation of such gauge or device. Gauges shall be regularly calibrated in accordance with the manufacturer's recommendations. Evidence of such calibration shall be available to the Division upon request.

Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, Public Resources Code.

§ 1724.11. Surface Expression Prevention and Response

(a) Underground injection projects shall not result in any surface expression.

(b) The following requirements apply to all underground injection projects that the Division determines have been known to cause a surface expression, and to all underground injection projects that involve the application of steam to a diatomaceous formation unless it has been demonstrated to the Division's satisfaction on a project-specific basis that surface expressions are not a concern for that project:

(1) The operator shall develop a surface expression monitoring and prevention plan for review and approval by the Division. At a minimum, the plan shall include the following:

(A) A subsurface injection-production mass balancing surveillance system utilizing a continuous tilt meter array or other ground monitoring system approved by the Division; or implementation of a real-time pressure/flow monitoring system that will give adequate warning to prevent surface expressions.

(B) A map of the project area with all surface expressions, including cracks, fissures, and sink holes related to underground injection, and containment measures prominently marked. A current map of these features shall be provided to the Division and shall be updated as these features are discovered, installed, or changed.

(C) Protocols for restriction of access to areas where there are surface expressions or surface expression containment measures.

(D) Training, including safety measures and identification of possible hazards, for field personnel working in areas where there are surface expressions or where surface expressions may occur.

(E) If the Division's determination that an underground injection project is subject to the requirements of this subdivision does not occur until after the Division's approval of the underground injection project, then the operator shall submit this plan to the Division within six months of the Division's determination.

(2) The operator shall have staff on site 24 hours a day to monitor underground injection project operations.

(3) The operator shall conduct daily visual inspections of all wells and production facilities associated with the underground injection project.

(4) The operator shall continuously monitor steam injection rates for active injection wells, and shall monitor injection pressures in accordance with Section 1724.10.4. If, over any 48-hour period, injection pressures show an unplanned variance of more than 25 percent or the injection rate shows an unplanned variance of more than 30 percent, the operator shall immediately notify the Division and initiate a diagnosis within 12 hours, including but not limited to:

(A) Confirmation of data.

(B) Inspection of wells and facilities associated with the anomaly.

(C) Review of overall system operations.

(D) Evaluation of ground monitoring data.

(5) If a diagnosis conducted pursuant to subdivision (b)(4) indicates there is a threat of steam leaving the approved injection zone, or if after 72 hours the diagnosis is inconclusive, then the operator shall immediately cease injection in wells with a wellhead that is within 300 feet of the wellhead of the well that experienced the variance. Injection may resume once the Division is satisfied that the threat has been resolved and the appropriate Division district deputy has provided the operator with written approval to restart injection.

(c) Operators shall immediately notify the Division if a surface expression occurs, increases in flow or size, or reactivates within the operator's lease. The notification to the Division shall include a list of all injection wells with a wellhead that is 300 feet or less from any point of the surface expression, ground monitoring data for no less than

14 days immediately preceding the occurrence, and additional data as may be requested by the Division.

(d) The operator shall immediately cease injection in a well if there is a surface expression within 150 feet of its wellhead. If the surface expression continues to flow for more than 24 hours, then the operator shall immediately cease injection in a well if the surface expression is within 300 feet of its wellhead. If the surface expression continues to flow for more than five days, then the operator shall immediately cease injection in a well if the surface expression is within 600 feet of its wellhead. If a surface expression continues to flow for more than 10 days, then the Division will determine an expanded radius around the surface expression within which injection shall cease. The Division will determine the expanded radius based on consideration of the flow rate of the surface expression, geologic factors, and operational parameters.

(e) The Division may direct injection to cease at any injection well, regardless of its distance from a surface expression, if the Division finds reason to believe that the injection well is causing or contributing to a surface expression.

(f) All wells that have ceased injecting pursuant to subdivisions (d) or (e) shall be prominently marked and tagged in the field to indicate that injection is not occurring.

(g) Wells that have ceased injecting pursuant to subdivisions (d) or (e) may not resume injection until the Division is satisfied that the cause of the surface expression has been determined and remediated and the appropriate Division district deputy has provided the operator with written approval to restart injection. With the advance written approval of the Division, the operator may be allowed to conduct limited injection for purposes of identifying the cause of a surface expression.

(h) If a surface expression discharges oil in a reportable quantity, then it shall be immediately reported as an oil spill to the Division and the California Governor's Office of Emergency Services at (800) 852-7550.

(i) Until there has been a determination by a professional engineer licensed under Chapter 7 of Division 3 of the California Business and Professions Code that the surface expression has stopped flowing and the area is safe for reentry, the area where a surface expression has occurred shall be cordoned off to restrict access to the surface expression. Additionally, the operator shall place prominent "Danger" or "Warning" signs, compliant with section 3340 of Title 8 of the California Code of Regulations, near (as safety dictates) the surface expression.

(j) As long as the Division concurs that a surface expression is a low-energy seep, the surface expression is not subject to the prohibition of subdivision (a) or the response requirements of subdivisions (d) through (g).

(k) The volume of any oil removed from the site of the surface expression shall be measured and reported to the Division, consistent with Public Resources Code section 3227, using a unique identifier assigned by the Division.

Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, Public Resources Code.

§ 1724.12. Surface Expression Containment

(a) The following requirements apply to the installation and use of surface expression containment measures, if any:

(1) The operator shall provide the Division with notice of construction of a surface expression containment measure to allow the Division to observe and document the installation.

(2) Surface expression containment measures shall be designed and signed off by, and construction supervised and approved by, a professional engineer licensed under Chapter 7 of Division 3 of the California Business and Professions Code. All surface expression containment measures shall be included in the operator's Spill Contingency Plan required under Section 1722.9, shall meet all federal, state, and local requirements, and shall ensure that surface expressions do not threaten surface water or USDWs.

(3) Upon completion of a surface expression containment measure, the licensed engineer shall provide a signed written report to the Division indicating whether the surface expression containment measure was constructed as designed and will safely and effectively contain and collect the flow from the surface expression.

(4) The operator shall monitor and record the rate of flow of the surface expression and monitor the containment measures at least daily, unless the Division has approved less frequent monitoring. The operator shall maintain records of the monitoring of the surface expression and containment measures for as long as the surface expression persists and provide them to the Division upon request. The operator shall immediately notify the Division if the surface expression increases in flow or size, reactivates, or

moves, or if there is any indication that the effectiveness of the surface expression containment measure has diminished.

(5) The operator shall map and prominently mark in the field all surface expression containment measures, and shall restrict access to such containment measures.

(b) Notwithstanding any efforts undertaken by the operator to contain a surface expression or otherwise mitigate risks associated with a surface expression, the existence of a surface expression, other than a low-energy seep, is a violation of the prohibition in Section 1724.11(a) against underground injection projects resulting in any surface expression.

Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, Public Resources Code.

§ 1724.13. Universal Operating Restrictions and Incident Response

(a) The operator shall cease injection into the affected injection well and immediately notify the Division if any of the following occur:

(1) The operator has not performed mechanical integrity testing on the well as required by Section 1724.10(i) or the notification and results required under Section 1724.10(i) have not been provided to the Division;

(2) The well failed a mechanical integrity test required by Section 1724.10(i) or there is any other indication that the well lacks mechanical integrity or is otherwise incapable of performing as approved by the Division;

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

(4) There is visible surface damage or erosion of the well location caused by injection;

(5) There is any indication that fluids being injected into the well are not confined to the approved injection zone;

(6) There is any indication that damage to life, health, property, or natural resources, or loss of hydrocarbons is occurring by reason of the injection;

(7) The operator has not provided information regarding the well as required under Public Resources Code section 3227;

(8) The well has become an idle well as defined by Public Resources Code section 3008, subdivision (d), unless the operator has requested and the Division has granted an allowance for the well to remain approved for injection for a longer period while the well is idle; or

(9) The Division instructs the operator in writing to suspend injection.

(b) The operator shall comply with all operational and remedial directives of the Division related to the reason for ceasing injection, and shall not resume injection into the well without subsequent written approval from the Division.

(c) Each day that injection occurs into an injection well in violation of this section shall be considered a separate violation. As required under Section 1777(c)(4), the operator shall disconnect injection lines from the injection well if there is no current approval from the Division for injection into the well.

Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Sections 3106 and 3236.5, Public Resources Code.

Subchapter 1.1. Offshore Well Regulations

Article 3. Regulations

1748. Underground Injection Control

Underground injection projects, as defined in Section 1720.1(p), including offshore underground injection projects, are subject to the provisions of Subchapter 1, Article 4.

Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, Public Resources Code.