

UPDATED UNDERGROUND INJECTION CONTROL REGULATIONS

PRE-RULEMAKING DISCUSSION DRAFT

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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 must be proposed by the operator as part of the underground injection project application, but may be specified by the Division depending on project-specific data and any other factors determined by the Division. The area of review is either:

(1) The calculated lateral distance in which the pressures in the injection zone may cause the migration of the injection fluid or the formation fluid out of the intended zone of injection; or

(2) A fixed one quarter mile radius.

(b) “Fluid” means liquid, gas, or steam.

(c) “Freshwater” means water that contains 3,000 TDS or less.

(d) “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.

(e) “Mechanical integrity” means that all well barrier envelopes, 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.

(f) “Surface expression” means a flow, movement, or release from the subsurface to the surface of oil, water, steam, gas, drilling mud, formation solids, formation debris, material, geothermal anomaly, or any combination thereof. Examples of surface expressions include, but are not limited to, fluid seepage, fissures, vents, fumaroles, hot springs, geysers, steaming ground, subsidence, ground fractures, craters, bubbling mud, uplift, landslides, thermal anomalies, or thermal infra-red hot-spots.

to the surface that is not through a well and that is caused by injection operations.

(g) “Surface expression containment measure” means an engineered measure undertaken in accordance with all state and local requirements to contain or collect the fluids 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.

(h) “TDS” means milligrams per liter of total dissolved solids content.

(i) “Underground injection project” means sustained or continual injection into one or more wells over an extended period into a defined, continuous three-dimensional volume with fixed boundaries in order to add fluid to a zone for the purpose of enhanced oil recovery, disposal, storage, pressure maintenance, or subsidence mitigation.

Examples of underground injection projects include, but are not limited to, waterflood injection, steamflood injection, cyclic steam injection, and injection disposal of produced fluid.

(j) “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

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

(ii) Contains fewer than 10,000 TDS.

AUTHORITY:

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

Article 3. Requirements

1724.6. Approval of Underground Injection Projects

(a) Operators Approval must be obtained from this the Division a Project Approval Letter for each underground injection project before any injection occurs as part of the underground injection project. subsurface injection or disposal project can begin. This includes all EPA Class II wells and air and gas injection wells. 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 Supervisor, are pertinent and necessary for the proper evaluation of the proposed project.

(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. All underground injection projects must 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 to verify compliance with the requirements of this subchapter and the terms and conditions of the Project Approval Letter, and will periodically review Project Approval Letters 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 sixty days after transfer of an underground injection project to a new operator, the new operator shall meet with the Division staff to ensure a complete

understanding of the applicable requirements and terms and conditions of the Project Approval Letter.

(g) Project Approval Letters shall expire, and be deemed null and void, upon the first day following twenty-four consecutive months of no injection at the underground injection project, and a new approval process and Project Approval Letter would be required prior to restarting injection.

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

1724.7. Project Data Requirements

~~—(Note: See Section 1724.8 for special requirements for cyclic steam projects, and Section 1724.9 for supplementary requirements for gas storage projects.)~~

~~The data required to be filed with the district deputy include the following, where applicable:~~

(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 zone or zones of injection and that the underground injection project will not cause damage to life, health, property, or natural resources. The operator is responsible for ensuring that the data are current throughout the operating life of the project, and account for all changes to the setting and operation of the project. The data filed with the Division shall include, at a minimum, the following:

(1) ~~(a)~~ An engineering and geological study demonstrating that injected fluid will not migrate out of the approved zone or zones through another well, geologic structure, faults, fractures, or fissures, holes in casing, or other means, including but not limited to:

(A) ~~(1)~~ Statement of primary purpose of the project.

(B) ~~(2)~~ Reservoir characteristics of each 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 intended reservoir rock and sealing mechanisms, the vertical interval above and below the intended reservoir, areas where fluid could potentially migrate, and the areas adjacent to the intended reservoir where potential migration of fluid or entrapment of migrated fluid could occur.

(C) ~~(3)~~ Reservoir fluid data for each injection zone, such as oil gravity and viscosity,

water quality, presence and concentrations of non-hydrocarbon components in the associated gas (such as hydrogen sulfide), and specific gravity of gas.

(D) A map of the area of review showing the location and status of all wells within and adjacent to the boundary of the area of review. The wellbore paths of all wells shall be shown, with indication of the interval penetrating the injection zone of the underground injection project.

(E) ~~(4)~~ Casing diagrams, including ~~cement plugs, and actual or calculated cement fill behind casing~~ all data specified in section 1724.7.1, of all ~~idle, plugged and abandoned, or deeper zone producing wells~~ that are within the area of review and that are completed in or penetrating the same or a deeper zone as the injection project, including directionally drilled wells that intersect the area of review in the same or deeper zone. ~~affected by the project, and evidence that plugged and abandoned.~~ The casing diagrams must demonstrate that the wells in the area will not be a potential conduit for fluid to migrate outside of the approved zone of injection or otherwise have an adverse effect on the project or cause damage to life, health, property, or natural resources.

(F) Identification of all wells within the area of review that do not penetrate the injection zone of the underground injection project, including a description of the total depth of such wells and the estimated top of the injection zone below such wells.

(G) ~~(5)~~ 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.

(H) Maps of the locations of 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 it is publicly available.

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

(A) ~~(1)~~ Structural contour map drawn on a geologic marker at or near the top of each injection zone in the project area, indicating known faults and other lateral containment features.

(B) ~~(2)~~ Isopachous map of each injection zone or subzone in the project area.

(C) ~~(3)~~ At least one geologic cross section in the project area through at least three wells, including one injection well in the project area.

(D) ~~(4)~~ Representative electric log to a depth below the deepest producing zone (if not already shown on the cross section), identifying all geologic units, formations, USDWs, freshwater aquifers, and oil or gas zones.

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

~~(A) (1)~~ A map showing injection facilities.

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

~~(C) (3)~~ Monitoring system or method to be utilized to ensure that no damage is occurring and that the injection fluid is confined to the ~~intended~~ approved zone or zones of injection. If groundwater monitoring is a component of the underground injection project, then documentation shall be provided of the results of the consultation with the State Water Resources Control Board or Regional Water Quality Control Board.

~~(D) (4)~~ Method of injection.

~~(E) (5)~~ List of proposed cathodic protection measures for plant, lines, and wells, if such measures are warranted.

~~(F) (6)~~ Treatment of water to be injected.

~~(G) (7)~~ Source and analysis of the injection ~~liquid~~ fluid, in accordance with section 1724.7.2.

~~(H) (8)~~ Location and depth of each water-source well that will be used in conjunction with the project.

(4) The results of all step rate tests, conducted in accordance with section 1724.7.3, for each injection well that is part of the underground injection project. Such data will be used to determine the maximum allowable injection pressure for the underground injection project. At the Division's discretion, this requirement may be satisfied by providing representative step rate test data from select wells within the underground injection project sufficient to establish a conservative ~~estimated~~ baseline fracture gradient for the entire area of the underground injection project. The Division may approve the use of an estimated baseline fracture gradient if, based on consideration of geologic, engineering, and operational factors, the Division is satisfied that the estimated baseline fracture gradient is lower than the actual fracture gradient that would be encountered anywhere in the area of review. If an estimated baseline fracture gradient is approved, a higher fracture gradient may be established for a specific well within the underground injection project using a well-specific step rate test conducted in accordance with section 1724.7.3.

~~(5) (d)~~ Copies of letters of notification sent to offset operators adjacent to the proposed underground injection project area and within the area of review.

~~(6) (e)~~ Other data as required for large, unusual, or potentially hazardous projects, for unusual or complex structures, or for critical wells. Examples of such data are: isogor

maps, water-oil ratio maps, isobar maps, 3-D maps, computer geologic models, equipment diagrams, and safety programs.

(7) Identification of all injection wells that are part of the underground injection project and all production wells that are intended to be affected by the underground injection project.

(8) Any data that, in the judgment of the Supervisor, are pertinent and necessary for the proper evaluation of the underground injection project.

(b) When a new injection well is added to an underground injection project, the operator shall provide the Division with any new data relevant to the addition of the new well, and shall update data previously provided to the Division if relevant conditions have changed or if more accurate data has become available. The addition of a new well does not require the operator to submit data previously provided to the Division.

(c) ~~(f)~~ All data required under this section shall be submitted to the Division electronically in a digital format subject to Division specification. All maps, diagrams, and exhibits required in subdivision (a) ~~Section 1724.7(a) through (e)~~ shall be clearly labeled, such as to scale and purpose, and shall clearly identify wells, boundaries, zones, contacts, and other relevant data.

(d) Where it is infeasible to supply the data specified in subdivision (a), the Division may accept alternative data, provided that the alternative data demonstrate to the Division's satisfaction that injected fluid will be confined to the approved zone or zones of injection, 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.

AUTHORITY:

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 section 1724.7, subdivision (a)(1)(E), shall meet the following requirements:

(1) Casing diagrams shall include all of the following data:

(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) Base of USDW;
 - ___ (F) Sizes, grades, connection type, and weights of casing and tubing;
 - ___ (G) Depths of shoes, stubs, and liner tops;
 - ___ (H) Depths of perforation intervals, water shutoff holes, cement port, cavity shots, cuts, casing damage, and type and extent of junk or fish left in well, and any other feature that influences flow in the well or may compromise the mechanical integrity of the well;
 - ___ (I) Information regarding associated equipment such as subsurface safety valves, packers, gas lift mandrels;
 - ___ (J) Diameter and depth of hole;
 - ___ (K) Cement plugs inside casings, including top and bottom of cement plug, with indication of method of determining;
 - ___ (L) Cement fill behind casings, including top and bottom of cement fill, with indication of method of determining;
 - ___ (M) Type and weight (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 well bores.
- ___ (2) Measured depth and true vertical depth shall be provided for all depths required under subdivision (a)(1).
 - ___ (3) Casing diagrams for all wells shall include a wellbore path giving both inclination and azimuth measurements.
 - ___ (4) Casing diagrams shall be submitted as both a graphical diagram and as a flat file data set.

AUTHORITY:

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

1724.7.2. Injection Fluid Analysis

(a) Unless the Division has approved an alternative fluid analysis protocol in accordance with subdivision (b), injection fluid analysis required under this Article shall include testing for all of the following: total dissolved solids; metals listed in California Code of Regulations, title 22, section 66261.24, subdivision (a)(2)(A); aluminum; antimony; arsenic; barium; beryllium; boron; cadmium; calcium; chromium; cobalt; copper; iron; lead; lithium; magnesium; manganese; mercury; molybdenum; nickel; potassium; selenium; silver; sodium; strontium; thallium; vanadium; zinc; Polynuclear Aromatic Hydrocarbons including, acenaphthene, acenaphthylene, anthracene, benzo(a)anthracene, benzo(b)fluoranthene, benzo(k)fluoranthene, benzo(a)pyrene, benzo(g,h,i)perylene, chrysene, dibenzo(a,h)anthracene, fluoranthene, fluorene, indeno(1,2,3-cd)pyrene, naphthalene, phenanthrene, and pyrene; radionuclides including, Gross alpha particle activity, Gross beta particle activity, Radium-226, Radium-228, Strontium-90, Tritium, and Uranium.

(b) The Division may approve alternative fluid analysis protocols on a project-specific basis as specified in the Project Approval Letter for the underground injection project, provided, however, that the State Water Resources Control Board or appropriate Regional Water Quality Control Board concurs with the alternative fluid analysis protocol. The alternative protocol may modify the list of constituents for analysis, but shall not decrease the frequency of fluid analyses required under section 1724.10, subdivision (d).

(c) Injection fluid analysis required under this Article shall be performed by a laboratory that is certified by the California Department of Public Health environmental laboratory accreditation program.

AUTHORITY:

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

1724.7.3. Step Rate Tests

(a) Step rate tests conducted to satisfy section 1724.7, subdivision (a)(4), shall meet the following requirements:

(1) When a step rate test is conducted on a formation with a permeability of greater than ten millidarcies the time steps shall be sixty minutes and the well shall be shut in until the bottom-hole pressures approximate shut-in formation pressures, but not less than forty-eight hours prior to the test.

(2) When a step rate test is conducted on a formation with a permeability of ten millidarcies or less the time steps shall be ninety minutes and the well shall be shut in until the bottom-hole pressures approximate shut-in formation pressures, but not less than seventy-two hours prior to the test.

(3) The first three steps of the step rate test shall be below the fracture gradient.

(4) Real time downhole pressure recording 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 before one full time step after the last step of the step rate test.

(b) Step rate test data reported under section 1724.7, subdivision (a)(4), shall 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. The step rate test data submitted to the Division shall be raw and unaltered.

(c) Operators shall provide the appropriate Division district office with at least twenty-four 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 section 1724.7, subdivision (a)(4).

AUTHORITY:

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

~~1724.8. Data Required for Cyclic Steam Injection Project Approval~~

~~—The data required by the Division prior to approval of a cyclic steam (steam soak) project include, but are not limited to, the following:~~

~~—(a) A letter from the operator notifying the Division of the intention to conduct cyclic steam injection operations on a specific lease, in a specific reservoir, or in a particular well.~~

~~—(b) If cyclic steam injection is to be in wells adjacent to a lease boundary, a copy of a~~

~~letter notifying each offset operator of the proposed project.~~

AUTHORITY:

~~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 zone of injection, 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 as the Division deems appropriate on a project-specific basis, to ensure that wells within the area of review will not be or become a potential conduit for fluid migration outside the approved zone of injection:

(1) All wells within the area of review that are completed in or penetrating the intended injection zone shall be evaluated for zonal isolation for the design of injection operation volumes, pressure, and flow rates. The operator should identify, and the Division confirm, wells which may require integrity testing or well logging in order to meet the integrity demonstration.

(2) Plugged and abandoned wells within the area of review must have cement across all perforations and extending at least 100 feet above the highest of the top of a landed liner, the uppermost perforations, the casing cementing point, the water shutoff holes, the intended zone of injection, or the oil and gas zone. The Division may select plugged and abandoned wells to be re-entered, examined, re-plugged and abandoned, or monitored to manage identified containment assurance issues prior to approval of injection.

(3) If plugged and abandoned wells within the area of review do not meet the required specifications of subdivision (a)(2), the Division may approve an alternative demonstration that there is hydrologic and geologic isolation, and injection will not cause or contribute to the migration of fluid outside the approved zone of injection, notwithstanding the presence of a plugged and abandoned well(s) lacking the specifications of subdivision (a)(2). The Division's approval of such an alternative demonstration shall be supported by written findings by the Division that identify each and every plugged and abandoned well in the area of review that fails to meet the

requirements of subdivision (a)(2), specify how the well(s) do not meet the requirements of subdivision (a)(2), and provide an explanation of the bases and data supporting the findings.

AUTHORITY:

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 alteration of conditions originally approved inconsistency with the current conditions of approval, such as: increase in size, change of injection interval, or increase in injection pressure. Such changes shall not be carried out without prior Division approval in accordance with section 1724.6.

(b) ~~Notices of intention to drill, redrill, deepen, or rework, on current Division forms, shall be completed and submitted to the Division for approval whenever a new well is to be drilled for use as an injection well and whenever an existing well is converted to an injection well, even if no work is required on the well.~~ 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 wells even where there is no alteration of casing, requires the prior written approval of the Division in accordance with section 1724.6.

(c) An injection report on a current Division form or in a digital-computerized format acceptable to the Division shall be filed with the Division on or before the 30th-last day of each month, for the preceding month.

(d) A chemical analysis of the ~~liquid-fluid~~ being injected, as specified in section 1724.7.2, shall be made and filed with the Division at least once every two years, whenever the source of injection ~~liquid-fluid~~ is changed or an additional source is introduced, or and as requested by the Supervisor Division.

(e) An accurate, operating, and well-specific injection pressure gauge or pressure recording device shall be installed at all times that a well is injecting ~~available at all times, and all injection wells shall be equipped for installation and operation of such gauge or device.~~ A gauge or device used for injection-pressure testing, ~~which is~~

~~permanently affixed to the well or any part of the injection system, shall be calibrated at least every six months, or as recommended by the manufacturer. Portable gauges shall be calibrated at least every two months.~~ Evidence of such calibration shall be available to the Division upon request. A Division-approved supervisory control and data acquisition (SCADA) or equivalent continuous real-time recording system, with automatic computer alarm notification, may be used to meet the requirements of this subdivision.

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

(g) All injection wells, ~~except steam, air, and pipeline-quality gas injection wells,~~ shall be equipped with tubing and packer set immediately above the approved zone of injection ~~within one year after the effective date of this act. New or recompleted injection wells shall be equipped with tubing and packer upon completion or recompletion.~~

Exceptions may be made when there is:

~~(1) No evidence of freshwater-bearing strata.~~

(1) (2) More than one string of casing cemented to the satisfaction of the Division below the base of fresh water any USDWs; or

(2) (3) Other justification, as determined by the Division district deputy, based on documented evidence that freshwater USDW, hydrocarbon, and high-pressure or other anomalous and oil zones can be protected without the use of tubing and packer.

(h) Data shall be maintained to show performance of the project and to establish that no damage to life, health, property, or natural resources is occurring by reason of the project. ~~Injection shall be stopped if there is evidence of such damage, or loss of hydrocarbons, or upon written notice from the Division.~~ Project data shall be available for periodic inspection by Division personnel.

(i) Maximum allowable surface pressure shall equal top perforation depth, in true vertical depth, multiplied by the difference between the injection gradient and the injectate fluid gradient (MASP = (IG – IFG) * TVD). The injection gradient used for this calculation shall be 0.95 multiplied by the fracture gradient as determined under section 1724.7, subdivision (a)(4). The Division may approve a higher maximum allowable surface injection pressure based on a demonstration by the operator that the injected fluid will remain confined to the intended zone of injection.

~~To determine the maximum allowable surface injection pressure, a step-rate test shall be conducted prior to sustained liquid injection. Test pressure shall be from hydrostatic~~

to the pressure required to fracture the injection zone or the proposed injection pressure, whichever occurs first. Maximum allowable surface injection pressure shall be less than the fracture pressure. The appropriate district office shall be notified prior to conducting the test so that it may be witnessed by a Division inspector. The district deputy may waive or modify the requirement for a step-rate test if he or she determines that surface injection pressure for a particular well will be maintained considerably below the estimated pressure required to fracture the zone of injection.

(j) ~~A m~~Mechanical integrity testing (MIT) must be performed on all injection wells to ensure the injected fluid is confined to the approved zone or zones. Mechanical integrity testing shall consist of a two-part demonstration in accordance with section 1724.10.1 and 1724.10.2. The operator shall notify the appropriate Division district office at least forty-eight hours, or other period acceptable to the district office, before performing any testing under sections 1724.10.1 and 1724.10.2 so that Division staff may witness the operations. Copies of surveys and test results shall be submitted digitally to the Division within sixty days of the tests. An MIT shall consist of a two-part demonstration as provided in subsections subsections (j)(1) and (2).

~~—(1) Prior to commencing injection operations, each injection well must pass a pressure test of the casing-tubing annulus to determine the absence of leaks. Thereafter, the annulus of each well must 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 appropriate Division district deputy.~~

~~—(2) When required by subsection (j) above, injection wells shall pass a second demonstration of mechanical integrity. The second test of a two-part MIT shall demonstrate that there is no fluid migration behind the casing, tubing, or packer.~~

~~—(3) The second part of the MIT must be performed within three (3) months after injection has commenced. Thereafter, water-disposal wells shall be tested at least once each year; waterflood wells shall be tested at least once every two years; and steamflood wells shall be tested at least once every five years. Such testing for mechanical integrity shall also be performed following any significant anomalous rate or pressure change, or whenever requested by the appropriate Division district deputy. The MIT schedule may be modified by the district deputy if supported by evidence documenting good cause.~~

~~—(4) The appropriate district office shall be notified before such tests/surveys are made, as a Division inspector may witness the operations. Copies of surveys and test results shall be submitted to the Division within 60 days~~

(k) 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. Project Approval Letters shall specify the monitoring program, including frequency intervals, for monitoring casing, wellheads, well safety systems, well piping, well site locations, injection pressure and flow rate, well annulus pressures or vents, pressures or fluid levels of any monitoring wells, and any other parameters deemed appropriate. In the event a Project Approval Letter does not specify a monitoring program, the operator shall take immediate steps to consult with the appropriate district office to ensure a monitoring program is added to the operating conditions for the underground injection project.

~~(lm)~~ (k) 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) List of all injection-withdrawal wells in a gas storage project, showing casing-integrity test methods and dates, the types of safety valves used, submitted to the Division annually.~~

~~(56)~~ Isobaric maps of the injection zone, submitted to the Division annually.

~~(67)~~ Notification of any change in waste disposal methods.

AUTHORITY:

Note: Authority cited: Section 3013, 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, each injection well must pass a pressure test of the

casing to determine the absence of leaks. Thereafter, the casing of each well must be tested at least once every five years, every time a packer is reset, or whenever requested by the appropriate Division district deputy. Injection must not occur into a well that has failed a pressure test until the well has been remediated to the satisfaction of the Division and passed a pressure test verifying the mechanical integrity of the well. Pressure testing is required even if the well is no longer an active injection well, unless the well is no longer approved for injection, has been plugged and abandoned, or has been converted to another purpose and is active. Testing under this subdivision shall conform to the following:

(1) Prior to conducting the test, the casing must be completely filled with liquid, and the temperature of the liquid in the well must be stabilized. Any additional substances such as polymer or other additives that increase viscosity may not be included in the well during testing unless approved in advance by the Division. Failure to obtain such advance approval could invalidate the test results.

(2) The casing shall be tested to the maximum allowable surface pressure, or 200 pounds per square inch (psi) measured at the surface, whichever is greater.

(3) The test pressure shall be held for thirty minutes with not more than ten percent overall change in pressure, provided during the final five minutes of continuous pressure testing the pressure gauge does not show more than an average of 0.5 percent change in pressure per minute.

(4) The pressure test shall be recorded with a pressure gauge, or other comparable device, of one percent accuracy or better, and the pressure recording shall be submitted to the Division in a digital format approved by the Division.

(b) Subject to the Division's approval, annular pressure monitoring consistent with this subdivision may be substituted for the pressure test described in subdivision (a).

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

(A) Information about the injection wells proposed to be monitored, including:

(i) Field, area, injection zone;

(ii) Well API number, well number, lease name;

(iii) Size of the tubing and packer and setting depth;

(iv) Date of last tubing and packer reset; and

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

(B) Information about the proposed pressure monitoring system, including:

(i) Pressure monitoring instrumentation, either wireless or hard-wired;

(ii) Computer data acquisition and storage systems; and
(iii) Reporting protocols, including clear identification of reportable statistical deviations.

(C) Schedule of injection project implementation, including the addition or removal of wells from the project.

(2) When alternative annular pressure monitoring has been approved by the Division, the operator shall adhere to the following requirements and limitations:

(A) The injection wells to be monitored shall initially pass a pressure test to at least 500 psi or the maximum allowable surface pressure, whichever is lower, and shall continue to pass such pressure tests every five years thereafter unless the maximum allowable surface pressure will be more than 500 psi, in which case such tests shall be performed and passed annually. Such pressure tests shall have a minimum of 200 psi differential between the tubing pressure and the casing annulus pressure.

(B) In order to demonstrate ongoing mechanical integrity, the operator shall demonstrate that the wells subject to annular pressure monitoring meet 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% of the tubing pressure or at least +/- 50 psi) between the annular pressure and the tubing pressure.

(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 that differ from the conditions of subdivision (b)(2)(B) 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, implementation of automatic casing pressure relief systems, automatic injection shutdown upon occurrence of upset conditions, and other back-up safety 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. The casing pressure test shall have a 200 psi differential between the tubing pressure and the casing annulus pressure.

(G) Any alternative monitoring method approved under this subdivision must be approved by the Division and tested by the operator at a frequency specified by the Division depending on the specific characteristics of the method.

AUTHORITY:

Note: Authority cited: Section 3013, 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, additional testing is required 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 this section, or other method approved by the Division. Operators shall obtain written approval from the appropriate Division district office regarding the testing method prior to performing the tests. Testing required under this section must be performed within three months after injection has commenced. Thereafter, injection wells shall be tested at least once each year, or on a testing schedule approved by the Division based upon consideration of the age of the well, geology, and operational factors. Testing required under this section shall also be performed following any significant anomalous rate or pressure change, or whenever requested by the Division. Testing described in this section is not required if the injection well is idle as defined by Public Resources Code section 3008, subdivision (d), but shall be performed within three months after recommencing injection. Testing

described in this section is not required for a cyclic steam well that has never injected more than 100 gallons per foot per injection cycle.

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

(1) Testing must 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 as close to the maximum injection rate as practical.

(2) There shall be an adequate pressure differential across the tubing wall in order for the for the test method to be valid.

(3) The casing valve must be open during testing and there must be no fluid flow. If fluid flow is indicated, the casing-tubing annulus shall be evaluated.

(4) Gamma ray detector sensitivity shall be set in consideration of lithologic effects.

(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) The test shall record measurements over a period of three to five minutes with the tool stationary at two points which are representative of the extremes of natural radiation within the interval to be tested.

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

(8) The slug of radioactive material shall be followed with the logging tool or make repeated passes upward through the slug as it moves down the well. 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 should be presented as a composite log on a common depth track. If means to differentiate the log traces are available no other presentation is required. If the traces cannot be differentiated on the composite log, they should also be presented individually.

(10) After any ejection, the slug of radioactive material must be followed until it has moved below the interval being tested. If the slug splits, all slug portions must be accounted for.

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

(12) If a well is injecting at a rate that creates a fluid velocity greater than one foot per second, radioactively treated beads shall be introduced into the well and evaluated according to subdivision (b)(8) through (b)(11) of this section.

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

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

(1) The well must be taken off injection at least twenty-four hours but not more than forty-eight hours prior to performing the temperature log, unless an alternate duration has been approved by the Division.

(2) The logging tool shall be calibrated to the extent feasible.

(3) The well must be logged from the surface downward, lowering the tool at a rate of no more than thirty feet per minute.

(4) If the well has not been taken off injection for at least twenty-four 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 electronically in either LAS or ASCII format.

(d) Noise Log. A noise log performed to satisfy the requirements of this section shall adhere to the following:

(1) Noise logging may be carried out while injection is occurring.

(2) Noise measurements must be taken at intervals of 100 feet to create a log on a coarse grid.

(3) If any anomalies are evident on the coarse log, there must be a construction of a finer grid by making noise measurements at intervals of twenty feet within the coarse intervals containing high noise levels.

(4) Noise measurements must be taken at intervals of ten feet through the first fifty feet above the injection interval and at intervals of twenty feet within the 100-foot intervals containing:

(A) The base of the lowermost bleed-off zone above the injection interval;

(B) The base of the lowermost USDW; and

(C) In the case of varying water quality within the zone of USDW, the top and base of each interval with significantly different water quality from the next interval.

(5) Additional measurements must be made to pinpoint depths at which noise is produced.

(6) A vertical scale of one or two inches per 100 feet shall be used.

(e) The operator shall take immediate action to investigate any anomalies, as compared to the historic record, 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.

AUTHORITY:

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 involve the application of steam to a diatomaceous formation and to any underground injection project that the Division determines has the potential to cause a surface expression:

(1) The operator shall develop and employ a sub-surface injection-production mass balancing surveillance plan utilizing a continuous tilt meter array, or other ground monitoring system approved by the Division, and implement a real-time pressure/flow monitoring system that will give adequate warning to prevent surface expressions.

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

(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 and pressures. If, over a twenty-four hour period, injection pressures show a variance of more than fifteen percent or the injection rate shows a variance of more than thirty percent, the operator shall immediately notify the Division and conduct a diagnosis within twelve hours, including but not limited to:

(A) Confirmation of data.

(B) Inspection of wells and facilities.

 (C) Review of overall system operations.

 (D) Evaluation of tilt meter data.

 (5) If a diagnosis conducted pursuant to subdivision (b)(4) indicates there is a threat of steam leaving the intended zone of injection, the operator shall immediately cease injection in wells with a bottom-hole location within 500 feet of the variance.

 (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 bottom-hole location 300 feet or less from any point of the surface expression, and ground monitoring data for the five days immediately preceding the occurrence.

 (d) The operator shall immediately cease injection in a well if there is a surface expression within 300 feet of the well's bottom-hole location, or if there is a surface expression that has been flowing for more than five days within 600 feet of the well's bottom-hole location. If a surface expression continues to flow for more than ten days, 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) If a surface expression occurs that has been determined to be associated to the steaming project, and is further away than 300 feet from the nearest well's injection interval, the operator must cease injecting into the nearest well until the cause has been determined and remediated.

 (f) All wells that have ceased injecting pursuant to subdivisions (d) or (e) must be prominently marked in the field and tagged 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 Supervisor is satisfied that the cause of the surface expression has been determined and remediated and the Division has provided the operator with written approval to restart injection.

 (h) If a surface expression discharges oil in a reportable quantity, then it shall be reported as an oil spill to the California Emergency Management Agency at (800) 852-7550.

 (i) Until there has been an evaluation by a professional engineer licensed under Chapter 7 of Division 3 of the California Business and Professions Code, and the Division is satisfied 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 deny access to the surface expression. Additionally, the operator shall place near the surface expression prominent warning signs consistent with the following standards:

(1) Warning signs shall have the signal word "WARNING" in black letters on a rectangular orange background placed at the top of the sign. The safety alert symbol (a triangle with equal sides of equal length surrounding an exclamation mark) shall precede the signal word and it shall be on the same horizontal line as the base of the letters of the signal word. Alternatively, warning signs may have the signal word "WARNING" in black letters with a safety orange truncated diamond on a black rectangular background.

(2) All signs shall have rounded corners and shall be free from sharp edges, burrs, splinters, or other sharp projections. The ends or heads of bolts or other fastening devices shall be located in such a way that they do not constitute a hazard.

AUTHORITY:

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 by, and construction shall be supervised by and signed off by both a professional geologist licensed under Chapter 12.5 of Division 3 of the California Business and Professions Code, and a professional civil engineer licensed under Chapter 7 of Division 3 of the California Business and Professions Code. All surface expression containment measures must meet all 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 civil engineer and licensed geologist 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 or collect the flow from the surface expression.

(4) The operator shall continuously monitor and record the rate of flow of the surface expression and monitor the containment measures. 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.

AUTHORITY:

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 shall not resume injection into the well without subsequent written approval from 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, subdivision (j), or the notification and results required under section 1724.10, subdivision (j), have not been provided to the Division;

(2) The well failed a mechanical integrity test required by section 1724.10, subdivision (j), 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 or well casing, including failures above or below a packer;

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

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

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

(7) The well has become an idle well as defined by Public Resources Code section 3008, subdivision (d); or

- (8) The Division instructs the operator in writing to suspend injection.
- (b) The operator shall immediately notify the Division upon ceasing injection operations by reason of subdivision (a), indicating the affected well and the specific reason for ceasing injection.
- (c) The operator shall comply with all operational and remedial directives of the Division related to the reason for ceasing injection.

AUTHORITY:

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

1724.14. Monitoring and Evaluation of Seismic Activity in the Vicinity of Injection Activity

(a) From commencement of injection activity, the operator shall continuously monitor the California Integrated Seismic Network for indication of an earthquake of magnitude 2.7 or greater occurring within a radius of one mile of injection operations.

(b) If an earthquake of magnitude 2.7 or greater is identified under subdivision (a), the following requirements apply:

(1) The operator shall immediately notify the Division and inform the Division when and where the earthquake occurred. If known, the epicenter and hypocenter shall also be reported to the Division.

(2) The Division, in consultation with the operator and the California Geological Survey, 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 subdivision (a) has been compromised.

AUTHORITY:

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