<u>REQUIREMENTS FOR CALIFORNIA UNDERGROUND GAS STORAGE PROJECTS</u>

DISCUSSION DRAFT

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

Subchapter 1. Onshore Well Regulations

[SECTION 1724.9 IS DELETED]

<u>NEW ARTICLE ADDED:</u>

Article 4. Requirements for Underground Gas Storage Projects

1726. Purpose, Scope, and Applicability.

The purpose of this article is to set forth regulations governing underground gas storage projects. Underground gas storage projects and gas storage wells are not subject to the requirements of Sections 1724.6 through 1724.10.

AUTHORITY:
Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, 3220 and 3403.5 Public Resources Code.

1726.1. Definitions.

(a) The following definitions are applicable to this article:

(1) “Area of review” means the volumetric vertical and horizontal extent of the reservoir used for underground gas storage and surrounding areas that may be subject to its influence. The area of review is delineated by the geologic extent of the reservoir such as impervious rock, structural closure, decrease or loss of porosity and permeability, or hydrodynamic forces in a three dimensional image.

(2) “Caprock” means the rock layer or layers at the upper boundary of the storage reservoir acting as the primary barrier preventing upward migration of fluids.

(3) “Fluid” means liquid or gas.

(4) “Gas storage well” means a well used to inject or withdraw gas from an underground storage project.

(5) “Reservoir” means the hydrocarbon reservoir that is being used to store natural gas in an underground gas storage project. The entire depth interval of a reservoir from the shallowest to the deepest depth can be subdivided into one or more depth intervals, which are referred to in this article as “zones”.

(6) “Underground gas storage project” means a project for the injection and withdrawal of natural gas into an underground reservoir for the purpose of storage. An underground gas storage project includes the reservoir used for storage, the confining caprock, gas storage wells, observation wells, and any other wells approved for use in the project. A gas storage project also includes the wellheads and, to the extent that they are subject to regulation by the Division, attendant facilities, and other appurtenances.

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1726.2. Approval of Underground Gas Storage Projects.

(a) A Project Approval Letter shall be obtained from the Division before any injection occurs as part of an underground gas storage project. The Project Approval Letter shall specify the location and nature of the underground gas storage project, as well as the conditions of the Division’s approval. Changes to the operational parameters of an underground gas storage project are subject to approval by the Division and shall be noted in either an addendum to the Project Approval Letter or a revised Project Approval Letter. Underground gas storage project operations shall not occur or continue unless consistent with the terms and conditions of a current Project Approval Letter.

(b) The Division will review underground gas storage projects to verify adherence to 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 effectively prevent damage to life, health, property, and natural resources. Ongoing approval of an underground gas storage project is at the Division’s discretion and a Project Approval Letter is subject to suspension, modification, or rescission by the Division.

(c) If the Division determines that operation of an underground gas storage project is inconsistent with 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 specified operations shall cease immediately, or as soon as it is safe to do so.

AUTHORITY:
Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, 3220 and 3403.5 Public Resources Code.

1726.3. Risk Management Plans.

(a) For each underground gas storage project, the operator shall submit a Risk Management Plan to the Division for review and approval. The Risk Management Plan shall identify potential threats and hazards to well and reservoir integrity, as well as life, health, property, and natural resources; assess risks based on potential severity and estimated likelihood of occurrence of each threat; identify the preventive and monitoring processes employed to mitigate each risk identified as well as overall and integrated risks; and specify a process for periodic review and reassessment of the risk assessment and prevention protocols. Risk assessment and prevention protocols shall be consistent with and additional to any other existing requirement in statute or regulation. The operator shall state what method and guidance it has followed in preparing the risk assessment. The Risk Management Plan shall specify a schedule for submission of risk assessment results to the Division. All Risk Management Plans shall include at least the following risk assessment and prevention protocols:

(1) Well construction and design standards, consistent with the requirements of Section 1726.5. If the operator has gas storage wells that are not in conformance with the requirements of Section 1726.5, then the Risk Management Plan shall include a work plan for either bringing the wells into conformance or phasing the wells out of use.

(2) For each gas storage well, employment as appropriate of surface and/or subsurface automatic or remote-actuated safety valves based on the following:

(A) The well's distance from dwellings, other buildings intended for human occupancy, or other well-defined outside areas where people may assemble such as campgrounds, recreational areas, or playgrounds;

(B) Gas composition, total fluid flow, and maximum flow potential;

(C) The distance between wellheads or between a wellhead and other facilities, and access availability for drilling and service rigs and emergency services;

(D) The risks created by installation and servicing requirements of safety valves;

(E) The risks to and from the well related to roadways, rights of way, railways, airports, and industrial facilities;

(F) Proximity to environmentally or culturally sensitive areas;

(G) Alternative protection measures which could be afforded by barricades or distance or other measures;

(H) Age of well;

(I) The risks of well sabotage;

(J) The current and predicted development of the surrounding area, topography and regional drainage systems and environmental considerations; and

(K) Evaluation of geologic hazards such as seismicity, active faults, landslides, subsidence, and potential for tsunamis.

(3) Ongoing verification and demonstration of the mechanical integrity of each well used in the underground gas storage project and each well that intersects the reservoir used for gas storage. The mechanical integrity testing protocols for gas storage wells shall, at a minimum, adhere to the requirements of Section 1726.6.

(4) Corrosion monitoring and evaluation including the following:

(A) Evaluation of tubular integrity and identification of defects caused by corrosion or other chemical or mechanical damage;

(B) Corrosion potential of wellbore produced fluids and solids, including the impact of operating pressure on the corrosion potential of wellbore fluids and analysis of partial pressures;

(C) Corrosion potential of annular and packer fluid;

(D) Corrosion potential of current flows associated with cathodic protection systems;

(E) Corrosion potential of all formation fluids, including fluids in formations above the storage zone; and

(F) Corrosion potential of uncemented casing.

(5) Ongoing evaluation of gas storage wells including monitoring of casing pressure changes at the wellhead, analysis of facility flow erosion, hydrate potential, individual facility component capacity and fluid disposal capability at intended gas and liquid rates and pressures, and analysis of the specific impacts that the intended operating pressure range could have on the corrosive potential of fluids in the system.

(6) Material balance monitoring in accordance with the requirements of Section 1726.7(b).

(7) Ongoing verification and demonstration of the integrity of the reservoir including demonstration that reservoir integrity will not be adversely impacted by operating conditions.

(8) Identification of potential threats and hazards associated with operation of the underground gas storage project including the following:

(A) Evaluation of likelihood of events and consequences related to the events;

(B) Determination of risk ranking to develop preventive and mitigating measures to monitor or reduce risk;

(C) Documentation of risk evaluation and description of the basis for selection of preventive and mitigating measures;

(D) Provision for data feedback and validation;

(E) Regular, periodic risk assessment reviews to update information and evaluate risk management effectiveness; and

(F) Analysis and risk assessment of geologic hazards including, and not limited to seismicity, faults, subsidence, inundation by tsunamis, sea level rise, and floods.

(G) Analysis and risk assessment of hazards associated with the potential for fire.

(9) If observation wells are employed, identification and documentation of baseline conditions such as wellbore pressure, pressure of monitored annuli, gas composition and liquid level.

(10) Consideration of potential for impacts to groundwater quality resulting from operations of the underground gas storage project.

(11) Prioritization of risk mitigation efforts based on potential severity and estimated likelihood of occurrence of each threat.

(12) An emergency response plan that accounts for the threats and hazards identified in the Risk Management Plan and that complies with the requirements of Section 1726.9.

(b) The Division will make completed Risk Management Plans and significant updates to the Risk Management Plans available to the California Public Utilities Commission. If any part of a

Risk Management Plan is subject to confidential treatment, then the Division will segregate the confidential records and only provide them if the California Public Utilities Commission has agreed to treat the records as confidential.

AUTHORITY:
Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, 3220 and 3403.5 Public Resources Code.

1726.4. Underground Gas Storage Project Data Requirements.

(a) For all underground gas storage projects, the operator shall provide the Division with data, analysis, and interpretation that demonstrate to the Division's satisfaction that stored gas will be confined to the approved zone(s) of injection and that the underground gas storage project will not cause damage to life, health, property, or natural resources. The operator shall provide the data specified in this section and any data that, in the judgment of the Supervisor, are pertinent and necessary for the proper evaluation of the proposed project. The data provided by the operator shall be to a level of detail and certainty satisfactory to the Division, and the operator shall ensure that required data is complete and current, regardless of the date of approval of the gas storage project. The data submitted to the Division shall include the following:

(1) Oil and gas reserves of all proposed storage zones prior to start of injection, including calculations, to indicate the storage capacity of the reservoir being considered for gas storage.

(2) Description of existing or proposed surface and subsurface safety devices, tests, and precautions to be taken to ensure safety of the project.

(3) Proposed produced water disposal method.

(4) Maximum and minimum reservoir pressure for the underground gas storage project and the data and calculations supporting the bases for the pressure limits. The pressure limits shall account for the following:

(A) The pressure required to inject fluids, particularly at total inventory, shall not exceed the design pressure limits of the reservoir, caprock, wells, well heads, piping or associated facilities.

(B) The minimum reservoir pressure shall take into account the historic minimum operating pressure and reservoir geomechanical competency. The impacts of intended minimum reservoir pressure shall be accounted for as it relates to geomechanical stress and liquid influx.

(5) An engineering and geological study demonstrating that injected gas will not migrate out of the approved zone or zones, such as through another well, geologic structure, faults, fractures or fissures, or holes in casing. The study shall include, but is not limited to:

(A) Statement of primary purpose of the project.

(B) 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.

(C) A comprehensive geologic characterization of the gas storage project including lithology of the storage zone or zones and sealing mechanisms as well as all formations encountered from surface to the deepest well in the project. The geologic characterization shall include any information that may be required to ensure injected or withdrawn gas does not have an adverse effect on the project or pose a threat to life, health, property or natural resources. The geologic characterization shall include potential pathways for gas migration and areas or formations where potential entrapment of migrated gas could occur. Information to accompany the geologic study shall include but is not limited to:

(i) Structure contour maps drawn on a geologic marker at or near the top of each gas storage zone in the project area, indicating faults and other lateral containment features.

(ii) Isopach map of each gas storage reservoir or subzone in the project area.

(iii) At least two geologic cross sections through at least four gas storage wells in the project area and the areas immediately adjacent.

(iv) Representative electric log to a depth below the deepest producing zone identifying all geologic units, formations, aquifers with groundwater that has 10,000 or less milligrams per liter of total dissolved solids content, aquifers with groundwater that has 3,000 or less milligrams per liter of total dissolved solids content, oil or gas zones, and gas storage reservoirs.

(v) Additional information including, but not limited to: isopach, isoGOR, isoBAR, structure-contour, 3-D, water-oil, or gas-oil ratio maps of the project and other information which will delineate all known features such as faults and fractures within the area of influence of the gas storage project.

(D) Reservoir fluid data for each gas storage zone, such as oil gravity and viscosity, water quality, presence and concentrations of non-hydrocarbon components in the associated gas (e.g. hydrogen sulfide, helium, etc.), and specific gravity of gas.

(E) 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 path of directionally drilled wells shall be shown, with indication of the interval penetrating the gas storage zone(s) of the underground gas storage project.

(F) Casing diagrams, including all data specified in Section 1726.4.1, of all wells that are within the area of review and that are in the same or a deeper zone as the gas storage project, including directionally drilled wells that intersect the area of review in the same or deeper zone. The casing diagrams must demonstrate that the wells in the area will not be a potential conduit for gas to migrate outside of the approved zone of gas storage or otherwise have an adverse effect on the project or cause damage to life, health, property, or natural resources. At a minimum, the casing diagrams must demonstrate that:

(i) Plugged and abandoned wells 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, or the intended zone of injection; and

(ii) Wells that are not plugged and abandoned and that have been inactive for more than two years have cement plugs across all hydrocarbon zones, the base of groundwater that has 10,000 or less milligrams per liter of total dissolved solids content, and groundwater that has 3,000 or less milligrams per liter of total dissolved solids content.

(G) Identification of all wells within the area of review that are not in the same or a deeper zone as the underground gas storage project, including description of the total depth of the well and the estimated top of the gas storage reservoir below the well.

(H) Wells completed in or penetrating through the intended gas storage reservoir shall be identified and evaluated for containment assurance for the design of gas storage 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. 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 gas storage operations.

(I) The planned or estimated well drilling and plugging and abandonment program to complete the project, showing all gas storage wells, plugged and abandoned wells, other wells related to the project, and unit boundaries.

(J) Maps of the locations of underground disposal horizons, mining, and other subsurface industrial activities not associated with oil and gas production or gas storage operations within the area of review, to the extent it is publicly available.

(6) A gas storage injection and withdrawal plan that includes all of the following:

(A) Maximum anticipated surface injection pressure and maximum anticipated daily rate of injection, by well.

(B) Monitoring system or method acceptable to the Division to be utilized to ensure the gas injected is confined to the intended approved zone(s) of injection.

(C) A wellhead monitoring system acceptable to the Division for the detection of leaks.

(D) A list of proposed cathodic protection measures for plant, lines, and wells, where employed.

(E) A summary of the source and analysis of the gas injected, submitted to the Division on an annual basis.

(7) The name and API number of all gas storage wells and other wells that are part of the underground gas storage project.

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

(b) Updated data shall be provided to the Division if conditions change or if more accurate data become available.

(c) All data filed with the Division under this section shall be submitted electronically, in a format acceptable to the Division. All maps, diagrams and exhibits shall be clearly labeled as to scale, north arrow, coordinate system, 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 gas will be confined to the approved reservoir or reservoirs of injection and that the underground gas storage project will not cause damage to life, health, property, or natural resources.

(e) The operator shall consult with the Division if the operator believes that there is a basis under state or federal law for confidential treatment of any data submitted to the Division. If the Division agrees that there is a basis for confidential treatment of data submitted, then the Division will take appropriate steps to maintain the confidentiality of that data.

(f) The Division will make all data received under this section available to the California Public Utilities Commission upon request. If the requested records are subject to confidential treatment, then the Division will only provide the records if the California Public Utilities Commission has agreed to treat the records as confidential.

AUTHORITY:
Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, 3220 and 3403.5 Public Resources Code.

1726.4.1. Casing Diagrams.

(a) Casing diagrams submitted under Section 1726.4 shall adhere to the following requirements:

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

(A) Operator, 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 groundwater that has 3,000 or less milligrams per liter of total dissolved solids content;

(E) Base of groundwater that has 10,000 or less milligrams per liter of total dissolved solids content;

(F) Sizes, weights, grades, and connection types of casing and tubing;

(G) Details on associated equipment such as subsurface safety valves, packers, gas lift mandrels;

(H) Depths of shoes, stubs, and liner tops;

(I) Depths of perforation intervals, water shutoff holes, cement port, cavity shots, cuts, patches, casing damage, top 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;

(J) Drill bit size diameter and depth of drilled hole;

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

(L) All cement fill behind casings, including top and bottom of cemented interval, with method of determination;

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

(N) Depths and names of the formation(s), zone(s), and geologic markers penetrated by the well, including the top and bottom of the gas storage zone(s);

(O) All information used to calculate the cement slurry (volume, density, yield), including but not limited to, cement type and additives, for each cement job; and

(P) All of the information listed in this paragraph for all previous drilled or sidetracked well bores.

(2) Measured depth and true vertical depth shall be provided for all measurements required under subdivision (a)(1).

(3) For directionally drilled wells, a directional survey shall be provided with inclination, azimuth measurements, and surface location.

(4) Casing diagrams shall be submitted in an electronic format acceptable to the Division.

(5) For all wells to be used for gas injection and/or withdrawal, the casing diagram shall include the mechanical well barrier elements that comprise the primary and secondary barriers as specified in section 1726.5.

AUTHORITY:
Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, 3220 and 3403.5 Public Resources Code.

1726.5. Well Construction Requirements.

(a) Operators shall design, construct, and maintain gas storage wells to effectively ensure mechanical integrity under anticipated operating conditions for the underground gas storage project. The operator shall ensure that a single point of failure does not pose an immediate threat of loss of control of fluids and make certain that integrity concerns with a gas storage well are identified and addressed before they can become a threat to life, health, property, or natural resources.

(b) Operators can demonstrate that a gas storage well adheres to the performance standard in subdivision (a) by demonstrating all of the following:

(1) The well has been completed with both primary and secondary mechanical well barriers to isolate the storage gas within the storage reservoir and transfer storage gas from the surface into and out of the storage reservoir.

(A) At minimum, the primary mechanical barrier shall be comprised of the following elements:

(i) Production casing to surface with the required integrity to contain reservoir pressure;

(ii) Tubing with packer and production tree with the required integrity to contain reservoir pressure; and

(iii) Surface Controlled Subsurface Safety Valve (SCSSV) or Christmas tree valve with the required integrity to contain reservoir pressure that halts flow through the well.

(B) At minimum, the secondary mechanical barrier shall be comprised of the following elements:

(i) Casing cement that overlaps at least 100 feet between two concentric casings, with good quality cement bond;

(ii) Wellhead with annular valves and seals and the required integrity to contain reservoir pressure;

(iii) Casing with hanger and seal assembly;

(iv) Tubing hanger with seals; and
(v) Christmas tree master valve.

(2) Each string of casing is designed to safely contain the expected internal and external pressures and tensile loads.

(3) The surface casing is of sufficient size, weight, grade, competency, and depth to support subsequent drilling operations.

(4) The production casing is of sufficient size, weight, grade, competency, and depth to maintain the well integrity, and is compatible with fluid chemical composition. The production casing is designed to accommodate fluids on injection and withdrawal at the maximum expected pressures and velocities. The production casing is free of open perforations or holes other than the planned completion interval(s). Perforations created for investigative or remedial work are sealed to establish hydraulic isolation.

(5) Casing connections are appropriate for use in the well design and exceed the expected mechanical loads.

(6) The gas storage well is cemented so as to maintain the integrity of the storage zone(s) by providing isolation of the reservoir from communication with other sources of permeability or porosity through the wellbore. Isolation is accomplished by filling the annular space between the casing and formation with competent cement to create a seal so that communication of fluids from the storage zone or other zones of interest is prevented.

(7) The cementing operations used a cement slurry designed for the anticipated wellbore conditions. All casing was cemented in a manner that ensures proper distribution and bonding of cement in the annular spaces. Additionally, cementing operations meet or exceed the following requirements:

(A) Surface casing is cemented with sufficient cement to fill the annular space from the shoe to the surface to protect ground water.

(B) Intermediate and production casings, if not cemented to the surface, are cemented with sufficient cement to fill the annular space to at least 500 feet above the gas storage reservoir, oil and gas zones or anomalous pressure intervals and to at least 100 feet above the base of groundwater that has 3,000 or less milligrams per liter of total dissolved solids content.

(8) Cement plugs provide for effective zonal isolation.

(9) Any remedial cement slurry and placement techniques are designed for the specific wellbore conditions, formations, and type of repairs.

(10) Cement bond log or evaluation acceptable to the Division is on file that indicates an adequate cement bond between the casing, cement and geologic formations. A competent cement bond extends across the caprock, and at least 100 feet above the gas storage reservoir.

(11) For wells equipped with tubing and packer, packer is set in cemented casing within caprock or at a location acceptable to the Division.

(c) If the operator does not demonstrate that a gas storage well meets the criteria of subdivision (b), then the operator shall demonstrate to the Division's satisfaction that an alternative method of well design and construction has been employed that effectively adheres to the performance standard of subdivision (a). The Division will determine on a case-by-case basis whether the operator has effectively demonstrated that a gas storage well that does not conform to the criteria in subdivision (b) meets the performance standard in subdivision (a).

AUTHORITY:
Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, 3220 and 3403.5 Public Resources Code.

1726.6. Mechanical Integrity Testing.

(a) The operator shall, at a minimum, conduct the following mechanical integrity testing on each gas storage well:

(1) A temperature and noise log shall be conducted at least annually to ensure integrity. All anomalies identified shall be immediately reported to the appropriate district office and explained to the Division's satisfaction.

(2) A casing wall thickness inspection, employing such methods as magnetic flux and ultrasonic technologies, shall be performed at least every two years to determine if there are possible issues with casing integrity. The results shall be compared against prior results and any other available data to determine the corrosion rate. If the casing wall thickness inspection indicate that within the next 24 months thinning of the casing will diminish the casing's ability to contain the well's maximum allowable operating pressure utilizing Barlow's equation or another method acceptable to the Division, then the well shall be remediated and shall not be used for injection or withdrawal without subsequent approval from the Division. The Division may approve a less frequent casing wall thickness inspection schedule for a well if the operator demonstrates to the Division's satisfaction that the well's corrosion rate is low enough that biennial inspection is not necessary.

(3) A pressure test of the production casing shall be conducted at least every two years. If injection in the gas storage well is through tubing and packer, then the pressure test shall be of the casing-tubing annulus of the well. Pressure tests shall be conducted at a pressure at least as high as 115 percent of the maximum operating pressure. A lower testing pressure may be approved by the Division if necessary to ensure that testing does not compromise the mechanical integrity of the well. Pressure testing shall be conducted with liquid unless the Division approves pressure testing with gas. If a pressure test does not indicate a final stabilized pressure and less than 10 percent pressure loss over a minimum 30 minute test, then the well shall not be used for injection or withdrawal without subsequent approval from the Division. The Division may require a longer duration of up to 60 minutes pressure testing based on individual circumstances. The Division may approve a less frequent pressure testing schedule for a well if the operator demonstrates to the Division's satisfaction that other measures to ensure the integrity of the well warrant less frequent pressure testing.

(b) A newly constructed gas storage well, or a reworked gas storage well that has had its existing production casing modified from its previous condition during rework activities, shall be tested as per subdivision (a).

(c) The Division may require additional testing as needed to demonstrate the integrity of the well.

(d) The appropriate district office shall be notified at least 48 hours before performing mechanical integrity testing so that Division staff may have an opportunity to witness the testing. All mechanical integrity testing shall be documented and copies of test results shall be submitted to the Division in an electronic format within 30 days.

AUTHORITY:
Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, 3220 and 3403.5 Public Resources Code.

1726.7. Monitoring Requirements.

(a) In addition to the mechanical integrity testing requirements under Section 1726.6, the operator shall monitor for the presence of annular gas by measuring and recording annular pressure at least once a day. The operator shall evaluate any anomalous annular gas occurrence and report it to the Division. This requirement may be met by employment of a real-time data gathering system, such as Supervisory Control and Data Acquisition.

(b) The material balance behavior of an underground gas storage project's storage reservoir shall be monitored relative to the original design and expected reservoir behavior. Unexpected conditions detected during monitoring shall be evaluated and corrected in order to avoid an incident or loss. Monitoring frequency should be based on factors such as reservoir and well fluid loss potential and flow potential, as outlined in the Risk Management Plan. Material balance support data will be submitted to the Division at least once a year, or upon request. Acceptable reservoir integrity monitoring and analysis methods include any of the following, or an equally effective method approved by the Division:

(1) Monitoring average reservoir pressure versus inventory and comparing that to expected conditions in order to allow for the discovery and correction of any anomalies or unexpected conditions. Liquid level shall be taken into account when utilizing observation wells. Semiannual field shut-in tests, usually conducted at the point of seasonally high and low inventories, shall be conducted for inventory verification.

(2) Installation and monitoring of strategically located observation wells in the vicinity of spill points, within an aquifer, and above the caprock in potential collector formations to detect the presence or movement of gas using methods which can include review of fluid level records, well pressures, geophysical logging, gas composition or other tools and methods deemed appropriate.

(3) Monitoring offset hydrocarbon production or disposal operations for unexplained flow or pressure changes. The monitoring shall include operations in zones above and below the storage reservoir as well as laterally offset locations.

(4) Conducting subsurface correlation and gas identification logs such as gamma ray-neutron logs to confirm the location of gas being injected into the intended storage reservoir, as needed.

(c) The operator of an underground gas storage project shall employ a real-time data gathering system, such as Supervisory Control and Data Acquisition, by January 1, 2020.

(d) The operator shall continually track all wells that are within the area of review and that are in the same or a deeper zone as the gas storage project and ensure that all such wells that are not plugged and abandoned and that have been inactive for more than two years have cement plugs across all hydrocarbon zones, the base of groundwater that has 10,000 or less milligrams per liter of total dissolved solids content, and groundwater that has 3,000 or less milligrams per liter of total dissolved solids content.

(e) The operator of an underground gas storage project shall adhere to an inspection and leak detection protocol that has been approved by the Division. The protocol shall include inspection of the wellhead assembly and attached pipelines for each of the gas storage wells used in association with the underground gas storage project, and the surrounding area within a 100-foot radius of the wellhead of each of the wells used in an underground gas storage project. The inspection protocol shall provide for inspection at least once a day, employing effective gas leak detection technology such as infrared imaging. The operator’s selection and usage of gas leak detection technology shall take into consideration detection limits, remote detection of difficult to access locations, response time, reproducibility, accuracy, data transfer capabilities, distance from source, background lighting conditions, geography, and meteorology. The Division will consult with the California Air Resources Board when reviewing an inspection and leak detection protocol submitted under this subdivision. The requirements of this subdivision shall cease to apply if the California Air Resources Board adopt and implement regulations with the same or stricter requirements.

AUTHORITY:
Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, 3220 and 3403.5 Public Resources Code.

1726.8. Inspection, Testing, and Maintenance of Wellheads and Valves.

(a) Where installed, the operator of an underground gas storage project shall test all surface and subsurface safety valve systems to ensure ability to hold anticipated pressure at least every six months. The tests shall be conducted in accordance with American Petroleum Institute Recommended Practice 14B (6th Edition, September 2015), or equivalent, to confirm operational integrity. The appropriate district office shall be notified at least 48 hours before performing testing so that Division staff may witness the operations, and documentation of the testing shall be maintained and available for Division review. A closed storage well safety valve system shall be re-opened with operator staff at the site of the valve to ensure the absence of any unforeseen issues. Within 90 days of finding that a surface or subsurface safety valve is inoperable, the operator shall either repair the safety valve or temporarily plug the well. An appropriate alternative timeframe for testing a valve or addressing an inoperable surface or subsurface safety valve may be approved by the Division.

(b) At least annually, the operator of an underground gas storage project shall test the master valve and wellhead pipeline isolation valve for proper function and verify ability to isolate the well.

(c) The operator shall equip gas storage wells with valves to provide isolation of the wells from the pipeline system and to allow for entry into the wells.

(d) The operator shall equip all ports on the wellhead assembly above the casing bowl of gas storage wells with valves, blind flanges, or similar equipment.

AUTHORITY:
Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, 3220 and 3403.5 Public Resources Code.

1726.9. Emergency Response Plan.

(a) The operator of an underground gas storage project shall have an emergency response plan approved by the Division and ready for immediate implementation. The emergency response plan shall specify a schedule for carrying out drills to validate the plan. The drills shall address the readiness of personnel and their interaction with equipment including required third party service providers and their current contact information.

(b) The emergency response shall at a minimum address the following scenarios:

(1) Collisions involving well heads;
(2) Well fires and blowouts;
(3) Hazardous material spills;
(4) Equipment failures;
(5) Natural disasters/emergencies;
(6) Leaks and well failures;
(7) Medical emergencies; and
(8) Explosions.

(c) The emergency response plan shall at a minimum include all of the following:

(1) Written actions plans establishing assigned authority to the appropriate qualified person(s) at a facility for initiating effective emergency response and control;
(2) Accident-response measures that outline response activities, leakage mitigation approaches, and well control processes for well failure and full blowout scenarios;
(3) Protocols for emergency reporting and response to appropriate government agencies
(4) Specification of personnel roles and responsibilities;
(5) Internal and external communication protocol;
(6) Emergency contact information including area codes; and
(7) Procedures for notification.

AUTHORITY:
Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106 and 3403.5 Public Resources Code.