

SB 463: Chemical Inventory and Root Cause Analysis Regulations

PRELIMINARY DISCUSSION DRAFT

CALIFORNIA CODE OF REGULATIONS, TITLE 14

DIVISION 2. DEPARTMENT OF CONSERVATION

CHAPTER 4. DEVELOPMENT, REGULATION, AND CONSERVATION OF OIL AND GAS RESOURCES

Subchapter 1. Onshore Well Regulations

Article 5. Requirements for Underground Gas Storage Projects

§ 1726.1. Definitions.

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

(1) "Area of review" means the three-dimensional 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 confining strata, structural closure, decrease or loss of porosity and permeability, or hydrodynamic forces in a three dimensional image.

(2) "Confining strata" means the rock layer or layers at the boundaries of the storage reservoir acting as the primary barriers preventing migration of fluids.

(3) "Fluid" means liquid or gas.

(4) "Gas storage well" means an active or idle well used primarily to inject or withdraw gas from an underground gas storage project.

(5) "Reservoir" means the portion of the geologic stratum 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 strata, gas storage wells, observation wells, and any other wells approved for use in the project. An underground 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.

(7) "Gas Storage Well Chemical Inventory" means a list of all chemical constituents that may be emitted from a gas storage well in the event of a reportable leak as defined in section 1726.9, subdivision (a).

Authority: Sections 3013, 3106 and 3180, Public Resources Code. Reference: Sections 3106, 3180, 3181.5, 3220 and 3403.5, Public Resources Code.

§ 1726.3. Risk Management Plans.

(a) For each underground gas storage project, the operator shall submit a project-specific Risk Management Plan to the Division for review and approval. For underground gas storage projects in existence at the time that this section goes into effect, the operator shall submit a Risk Management Plan in accordance with the requirements of this section within six months of the effective date of this section. If the Division identifies any deficiencies in the Risk Management Plan, then the Division will consult with the operator and identify an appropriate timeframe for correcting the deficiency. The Risk Management Plan shall specify a schedule for the operator to review and submit updates to the risk assessment and prevention and mitigation protocols to the Division. The Division will review the Risk Management Plan periodically, but not less than once every three years.

(b) The Risk Management Plan shall demonstrate that stored gas will be confined to the approved reservoir and that risks of damage to life, health, property, the environment, or natural resources are identified and prevented or effectively mitigated. In accordance with subdivision (c), the Risk Management Plan shall evaluate threats and hazards associated with operation of the underground gas storage project and identify prevention and mitigation protocols that effectively address those threats and hazards. The Division may, in its discretion, require additional data, additional risk

assessment, or modification of prevention and mitigation protocols. Risk assessment and prevention and mitigation protocols in the Risk Management Plan shall be consistent with and in addition to any other existing requirements.

(c) The Risk Management Plan shall include a description of the methodology employed to conduct the risk assessment and identify prevention and mitigation protocols, with references to any third-party guidance followed in developing the methodology. The methodology shall include at least the following:

(1) Identification of potential threats and hazards associated with operation of the underground gas storage project, including identification of the most important potential accident scenarios associated with operation of the underground gas storage project;

(2) Quantitative risk assessment of the probability of threats and hazards and their consequences, using an appropriate methodology identified by the operator that includes:

(A) Evaluation of the frequency and range of consequences, including estimates of the uncertainties in the numerical values;

(B) Identification of the principal equipment failures, external initiating events, and operational errors associated with threats and hazards, and quantification of the impact of these occurrences on the probability of and consequences of the threats and hazards; and

(C) Identification of the engineered or natural features that most affect the extent of the consequences of threats and hazards, and a quantification of their relative roles, including an estimate of the uncertainties in the quantification;

(3) Identification of possible prevention and mitigation protocols to reduce, manage, or monitor risks, including evaluation of the efficacy and cost-effectiveness of the prevention protocols;

(4) Risk assessment on a well-by-well basis, to the extent that risks identified are specific to wells;

(5) Prioritization of risk prevention and mitigation efforts based on potential severity and estimated likelihood of occurrence of each threat;

- (6) Selection and implementation of prevention and mitigation protocols;
- (7) Documentation of the risk assessment process, including description of the basis for selection of prevention and mitigation protocols;
- (8) Data feedback and validation throughout the risk assessment process; and
- (9) Regular, periodic risk assessment reviews to update information and evaluate the effectiveness of prevention and mitigation protocols employed, which shall occur not less than once every three years and in response to changed conditions or new information.

(d) In addition to the contents required in subdivision (b), all Risk Management Plans shall include at least the following risk assessment and prevention and mitigation protocols:

(1) Well construction and design standards, consistent with the requirements of Section 1726.5 and including specification of the life expectancy of individual mechanical well barrier elements. If the operator has wells that do not conform with the requirements of Section 1726.5, then the Risk Management Plan shall include a work plan and schedule for either bringing the nonconforming wells into compliance or plugging and abandoning the wells in accordance with Public Resources Code section 3208. The work plan and schedule shall provide for full compliance with Section 1726.5 within seven years, with at least 10 percent of the nonconforming wells addressed in the first year and the total percentage of the nonconforming wells addressed increasing by 15 percent in each subsequent year. The work plan shall include prevention and mitigation protocols for monitoring and testing each well that is not yet in compliance with the requirements of Section 1726.5 so as to mitigate risks associated with the well to the extent feasible.

(2) For each gas storage well, evaluation of whether employment of surface and/or subsurface automatic or remote-actuated safety valves is appropriate based on consideration of at least 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, operational pressures, 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 sabotage;

(J) The current and predicted development of the surrounding area as reflected in the local general plan, topography and regional drainage systems, and environmental considerations;

(K) Topography and local wind patterns; and

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

(3) A schedule for 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, evaluation, and mitigation including consideration of at least 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 pressures, temperatures, and compositions 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.~~

(4) For each gas storage well, corrosion evaluation, corrosion risk mitigation strategies, and monitoring protocols in accordance with the requirements of Section 1726.3.2.

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

(6) Monitoring protocols in accordance with the requirements of Section 1726.7.

(7) Protocols in accordance with the requirements of Section 1726.3.3 for defining, investigating, tracking, and reporting to the Division any off-normal occurrence that could adversely affect an operator's facilities or operations, even if the occurrence did not result in harm to the facility, health and safety, the environment, or natural resources.

~~(78)~~ Ongoing verification and demonstration of the integrity of the reservoir including demonstration that reservoir integrity will not be adversely impacted by operating conditions.

~~(89)~~ Analysis and risk assessment of hazards associated with the formation of hydrates, and scale from the well stream under various pressure, temperature, and flow rates, including those beyond expected operating parameters.

~~(910)~~ Analysis and risk assessment of natural and geologic hazards including, but not limited to, seismicity, faults, subsidence, inundation by tsunamis, sea level rise, and floods.

(1011) Analysis and risk assessment of hazards associated with the potential for explosion or fire.

(1112) If observation wells are employed, identification and documentation of baseline conditions such as wellbore pressure, pressure of monitored annuli, gas composition and liquid level.

(1213) An assessment of human factors in operating and maintenance procedures. The human factors assessment shall consider ~~staffing levels; the complexity of tasks; the length of time needed to complete tasks; the level of training, experience and expertise of employees; the human-machine and human-system interface; the physical challenges of the work environment in which the task is performed; employee fatigue and other effects of shiftwork and overtime; communication systems; and the understandability and clarity of operating and maintenance procedures.:~~

(A) staffing levels;

(B) the complexity of tasks;

(C) the length of time needed to complete tasks;

(D) the level of training, experience and expertise of employees and contractors;

(E) the human-machine and human-system interface;

(F) the physical challenges of the work environment in which the task is performed;

(G) employee fatigue and other effects of shiftwork and overtime;

(H) communication systems; and

(I) the understandability and clarity of operating and maintenance procedures.

(14) The human factors assessment shall also consider utilization of error-proof mechanisms, automatic alerts, and automatic system shutdowns.

(1315) An effective training program with clearly stated goals. The training program shall specify the type and frequency of training and the risk assessments and prevention and mitigation protocols addressed.

(~~1416~~) An equipment maintenance program that includes training and proactive inspection, repair, and replacement of equipment at risk of failure so as to ensure safe operation.

(~~1517~~) An emergency response plan that at a minimum accounts for the threats and hazards identified in the Risk Management Plan and that complies with the requirements of Section 1726.3.1.

(~~1618~~) Requests for notice from land use agencies of local land use decisions that could affect the Risk Management Plan, and providing notification to the Division of significant pending land use decisions.

(e) The operator shall adhere to the risk prevention and mitigation protocols detailed in its Risk Management Plan unless a variance has been approved by the Division in writing.

(f) The Division will provide completed Risk Management Plans and significant updates to the Risk Management Plans to the California Public Utilities Commission and post them on the Division's public internet website. 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: Sections 3013, 3106 and 3180, Public Resources Code. Reference: Sections 3106, 3180, 3181, 3186.3, 3220 and 3403.5, Public Resources Code.

§ 1726.3.1. 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 operator personnel with respect to their ability to interact with equipment and their ability to contact required third party service providers for the equipment. The emergency response plan shall identify and consider onsite personnel, outside emergency responders, and potentially affected

communities. The operators shall provide local emergency response entities at least 30 days to review and provide input on the emergency response plan.

(b) The emergency response plan 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) Clearly written and communicated emergency response plan policy, goals, and objectives;

(2) An incident management system designed to address resource management, communication systems, and incident documentation;

(3) Written action plans establishing assigned authority to the appropriate person(s) at a facility for initiating effective emergency response and control;

(4) Accident-response measures that outline response activities, leakage mitigation approaches, and well control processes for well failure and full blowout scenarios;

(5) Well-specific well control plans that include an Inflow Performance Relationship and the data or modeling that the Inflow Performance Relationship is based upon for the current configuration of the well.

~~(5)~~ Prepositioning, as feasible, and identification of materials and personnel necessary to respond to leaks, including materials and equipment to respond to and stop the leak itself as well as to protect public health and safety.

~~(67)~~ A schedule for regular drills, providing for an opportunity for involvement of the Division and local emergency response entities, and providing an opportunity for drills initiated by local emergency response entities;

~~(78)~~ An effective training program with clearly stated goals. The training program shall specify the type and frequency of training and the emergency scenarios addressed;

~~(89)~~ Recordkeeping for all drills and training;

~~(910)~~ A schedule for regular evaluation and update of the emergency response plan;

~~(1011)~~ Protocols for emergency reporting and response to appropriate government agencies;

~~(1112)~~ Specification of personnel roles and responsibilities;

~~(1213)~~ Internal and external communication protocol;

~~(1314)~~ Up-to-date emergency contact information including area codes; and

~~(1415)~~ A protocol for public notice of a large, uncontrollable leak to any potentially impacted community, as defined in the Risk Management Plan, if the leak cannot be controlled within 48 hours of discovery by the operator. (d) The operator shall review and update the emergency response plan after key personnel changes, but no less often than once every three years. When reviewing and updating the emergency response plan, the operator shall again provide local emergency response entities at least 30 days to review and provide input on the emergency response plan.

(16) Identification of monitoring, sampling, and testing methods, to be utilized to detect and, if possible, quantify each chemical of concern emitted during a reportable leak. For the purposes of this section, "chemical of concern" includes hydrogen sulfide, benzene, toluene, ethylbenzene, xylenes, radon 222, and other constituents that the Division requires testing for under Section 1726.3.4, subdivision (c).

Authority: Sections 3013, 3106 and 3180, Public Resources Code. Reference: Sections 3106, 3180, 3181, 3183, 3184, 3181.5, 3186.3, and 3403.5, Public Resources Code.

§ 1726.3.2. Corrosion Evaluation, Mitigation, and Monitoring.

(a) A Risk Management Plan under Section 1726.3 shall include prevention and mitigation protocols that, for each gas storage well, provide for corrosion evaluation, corrosion risk mitigation strategies, and monitoring protocols.

(1) Each gas storage well's corrosion risks shall be evaluated, and the risk assessment of each well shall consider at least the following:

(A) Evaluation of the well's components including tubular integrity and the configuration and corrosion potential of its casings.

(B) The well's corrosion rate, as determined under Section 1726.6, subdivision (a)(2).

(C) Anomalies identified in logs or tests run on the well.

(D) The well's age, history of use and maintenance including drilling and completion, mitigations and repairs, replacements, and current use.

(E) Composition of all annular fluids where casing strings are not cemented to surface.

(F) Evaluation by well of environmental conditions including at least the following:

(i) Composition and anticipated corrosivity of wellbore fluids and solids, including the impact of operating pressures and temperatures;

(ii) Composition and corrosivity of all formation fluids, including fluids in formations above the storage zone;

(iii) Surface and near surface hydrology;

(iv) Surface soil conditions;

(v) Location of the well relative to other wells; and

(vi) History of other environmental factors that may contribute to corrosivity.

(2) The prevention and mitigation protocols shall include corrosion risk mitigation strategies for each gas storage well that include at least the following:

(A) Prioritization of the corrosion risks to be mitigated.

(B) Strategies to mitigate each corrosion risk and the anticipated effectiveness of each strategy. Mitigation strategies evaluated for each well shall at a minimum include cathodic protection, coatings, inhibitors, and material selection or replacement.

(C) Evaluation of cathodic protection as a possible mitigation strategy shall be documented for each well. If cathodic protection is implemented, then the documentation shall include:

(i) References to the industry standards used to define the protection criteria, and

(ii) Description of how the cathodic protection system is used to mitigate corrosion risks.

(3) The prevention and mitigation protocols shall include corrosion monitoring protocols for each gas storage well that include at least the following:

(A) A plan for monitoring and evaluating the effectiveness of each corrosion risk mitigation strategy used. The monitoring plan shall be updated promptly when mitigation strategies change.

(B) The operator shall reevaluate the corrosion risk mitigation strategies in use every time casing wall thickness inspection is conducted under Section 1726.6, subdivision (a)(2) and any time new corrosion data indicates a need for reevaluation. Reevaluation of corrosion risk mitigation strategies shall include consideration of newly developed corrosion mitigation technologies and practices.

Authority: Sections 3013, 3106 and 3180, Public Resources Code. Reference: Sections 3106, 3180, 3181, 3186.3, 3220 and 3403.5, Public Resources Code.

§ 1726.3.3. Monitoring and Reporting Off-Normal Occurrences.

(a) A Risk Management Plan under Section 1726.3 shall include prevention and mitigation protocols for defining, investigating, tracking, and reporting to the Division any off-normal occurrence that could adversely affect an operator's facilities or operations, even if the occurrence did not result in harm to the facility, health and

safety, the environment, or natural resources. Examples of such off-normal occurrences include but are not limited to:

- (1) Loss of containment of a well;
- (2) Damage to a wellhead or other surface or subsurface equipment;
- (3) Any crack or other material defect that impairs the structural integrity of wells;
- (4) Damage caused by well work activities;
- (5) Movement or abnormal loading by environmental causes, including but not limited to earthquakes, landslides, wildfires and floods;
- (6) Exceeding maximum allowable operating pressure for any well;
- (7) Installation of incorrect equipment;
- (8) Damage to a tank or vessel attendant to the underground gas storage project;
- (9) Work activity in which a standard, procedure, or process was correctly applied but the activity nonetheless resulted in a situation or condition that threatened or caused harm or damage;
- (10) Situations where failure to follow procedures could have resulted in a potentially hazardous condition;
- (11) Unauthorized entry or malfeasance, including but not limited to trespassing, arson, destruction of property, or removal of fencing;
- (12) Incorrect, unintended, or unintentional operation of any equipment necessary to safe operation of the underground gas storage project; and
- (13) Any other condition, situation or event that could lead to a hazard.

(b) Operators shall report any off-normal occurrence to the Division within 90 days of the discovery of the occurrence. The report shall include findings from the investigation of the off-normal occurrence, describe measures implemented to correct or remediate the off-normal occurrence and measures taken to prevent reoccurrence.

(c) If the operator has not completed the investigation and remediation of an occurrence at the time the it is reported to the Division, then the operator shall provide the Division supplemental reports on that occurrence at least once every 30 days until the occurrence fully investigated and remediated.

(d) The data and findings from the operator's off-normal occurrence investigations shall inform updates and improvements to the risk management plan methodology described in Section 1726.3, subdivision (c).

Authority: Sections 3013, 3106 and 3180, Public Resources Code. Reference: Sections 3106, 3180, 3181, 3186.3, 3220 and 3403.5, Public Resources Code.

§ 1726.3.4. Gas Storage Well Chemical Inventory.

(a) For each gas storage well, the operator shall maintain a Gas Storage Well Chemical Inventory that lists all chemical constituents that may be emitted from a gas storage well in the event of a reportable leak as defined in section 1726.9, subdivision (a). The Gas Storage Well Chemical Inventory shall identify on a well-by-well basis all chemical constituents found in materials of any phase that may be emitted from the well.

(1) For purposes of this section, materials that may be emitted from the well include, but are not limited to:

(A) The formation fluids;

(B) Gas in the storage reservoir;

(C) Wellbore-produced fluids;

(D) Fluids placed in the well for any purpose;

(2) For purposes of this section, fluids include suspended or entrained solids.

(b) The Gas Storage Well Chemical Inventory shall include the Chemical Abstract Service Number of each chemical constituent identified. If a chemical does not have a Chemical Abstract Service number, then the operator shall provide other available identification information.

(c) The Gas Storage Well Chemical Inventory shall include analytical test results and analysis of the chemical constituents present in the reservoir. The tests and analysis shall at a minimum include testing for hydrogen sulfide, benzene, toluene, ethylbenzene, xylenes, and radon 222. Sampling and testing for radon 222 shall be conducted at the end of an injection season to best estimate peak radon 222 concentration. The Division

may require testing and analysis for additional constituents based on indication that other potentially harmful chemicals may be found in the reservoir.

(d) The operator shall develop and adhere to a protocol for maintaining and providing to the Division a Gas Storage Well Chemical Inventory, and that protocol shall meet the following requirements:

(1) The protocol shall include procedures to ensure that whenever fluid is placed in the well, all the chemical constituents of the fluid are identified and promptly included in the Gas Storage Well Chemical Inventory. The protocol shall include procedures to track:

(A) The dates when a chemical constituent is placed in the well;

(B) The volume, within a 10 per cent margin of error, of each chemical constituent placed in the well on a given date; and

(C) The cumulative volume, within a 10 per cent margin of error, of each chemical constituent placed in the well.

(2) The protocol shall include procedures to be implemented in the event of a reportable well leak to ensure that within five days of using a kill fluid the operator will provide the Division an updated Gas Storage Well Chemical Inventory including each chemical constituent of the kill fluid. If the operator is unable to obtain information about chemical composition of a kill fluid for any reason, including, but not limited to, assertion by the supplier of trade secret protections, then the operator shall immediately notify the Division with the name and contact information of the supplier and available information about the well kill materials or chemicals therein. These procedures shall be incorporated into the Emergency Response Plan required under Section 1726.3.

(3) The protocol shall require that the chemical information for each gas storage well is specifically identified, recorded, maintained and reported by well in the Gas Storage Well Chemical Inventory.

(4) The protocol shall require the operator to provide the Gas Storage Well Chemical Inventory to the Division in a digital format {within six months of the effective date} of this section and provide an updated Gas storage Well Chemical Inventory to

the Division every twelve months thereafter. The protocol shall also call for submittal of an updated Gas Storage Well Chemical Inventory to the Division within 30 days of key changes occurring, such as when new chemicals are introduced due to well work which includes but is not limited to well completion, well maintenance, or well testing.

(5) The protocol shall include a workplan for completing the analytical testing and analysis requirements referenced in subdivision (c).

(6) The protocol shall be submitted to the Division for review and approval {within three months of the effective date} of this section and when the protocol is updated.

Authority: Sections 3013, 3180 and 3106, Public Resources Code. Reference: Sections 3106, 3180, 3181, 3181.5, 3220 and 3403.5, Public Resources Code.

§ 1726.6.1. Pressure Testing Parameters.

(a) Pressure testing required under Section 1726.6 shall be conducted according to the following parameters:

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

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

~~(23)~~ The wellbore shall be filled with a stable column of fluid that is free of excess gasses.

~~(34)~~ Pressure tests shall be recorded and a calibrated gauge shall be used that can record a pressure with an accuracy within one percent of the maximum allowable injection pressure.

~~(45)~~ Pressure tests shall be conducted at an initial test pressure of at least 115 percent of the maximum allowable injection pressure at the wellhead.

~~(56)~~ The pressure test shall be continuous for one hour. A pressure test is successful if the pressure gauge does not show more than a 10 percent decline from the initial test pressure in the first 30 minutes, and does not show more than a 2 percent decline from the pressure after the first 30 minutes in the second 30 minutes.

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

Authority: Sections 3013, 3106 and 3180, Public Resources Code. Reference: Sections 3106, 3180, 3181, 3220 and 3403.5, Public Resources Code.

DRAFT