

REQUIREMENTS FOR CALIFORNIA UNDERGROUND GAS STORAGE PROJECTS

PUBLIC COMMENT SUMMARY AND RESPONSE

**45-day Public Comment Period:
May 19, 2017 through July 13, 2017**

INTRODUCTION

The following comments, objections, and recommendations were made regarding the proposed Requirements for California Underground Gas Storage Projects rulemaking action during a public comment period beginning May 19, 2017 and ending July 13, 2017. During that public comment period, two public comment hearings were conducted, one in Sacramento on July 10, and one in Los Angeles on July 12.

Over the course of the public comment period, the Division received a number of public comments via email, regular mail, public comment hearing, and fax. These comments ranged from detailed comments on the proposed requirements to general concerns about facility safety. To facilitate the process of reviewing and responding to comments, the Division assigned to each comment a unique numerical signifier. This signifier consists of three components: first, a unique code number assigned to each commenter; second, a separating hyphen; third, a sequential number assigned to each comment from the identified commenter. The chart below lists the code number for each commenter. Within this document, you will find either grouped or individual numerical signifiers, followed by a summary or specific comment, followed by a response (italicized).

COMMENTERS

Number	Name and/or Entity
0001	Joseph K. Goldstein
0002	Richard Bratkovich
0003	California Independent Petroleum Association / Western States Petroleum Association
0004	Ben Kaczor
0005	Wendy Krowne
0006	Don Dwiggins
0007	Liz Tigelaar

0008	Anneliese Anderle
0009	Diane Fletcher-Hoppe
0010	Environmental Defense Fund / Pipeline Safety Trust
0011	Patty Glueck
0012	Lori Kalman
0013	Rashelle Zelaznik
0014	Sandi Naiman
0015	Tom Williams / Citizens Coalition for a Safe Community
0016	Vikki Salmela
0017	Los Angeles County
0018	Los Angeles County Public Health
0019	Los Angeles County Fire Department
0020	INGAA Interstate Natural Gas Association of America
0021	Geologic Map Foundation
0022	Independent Storage Providers
0023	Picarro
0024	PG&E Pacific Gas & Electric
0025	NRDC Natural Resources Defense Council
0026	SoCalGas / Sempra Energy
0027	Save Porter Ranch / PARRIS Law Firm
0028	Patricia Lacara
0029	Melanie Demont
0030	Center for Biological Diversity
0031	A Concerned Citizen
0032	Mike Valiance, Gil Ranch Storage & ISP Coalition
0033	Jen Glueck
0034	Logan Smith
0035	Richard Matthews
0036	Dr. Leah Garland

0037	Andrea Grossman (Leon-Grossman), Food and Water Watch
0038	Laurie Gral
0039	Leonard Chansky
0040	Jane Fowler
0041	Deidre Balona
0042	Helen Attai
0043	Elena Semper
0044	Unique Vance
0045	Alena Simon, Food and Water Watch
0046	Alexandra Nagy, Food and Water Watch
0047	Daryl Gale
0048	Emily Choi
0049	Rachel Enders
0050	Hsimlai Hsu
0051	Tyler Aguirre
0052	Clean Water Action / Environmental Working Group / The Wildlands Conservancy / Grassroots Coalition / Citizens Coalition for a Safe Community / Earthworks

ACRONYMS

AOR	Area of Review
API RP	American Petroleum Institute Recommended Practice
CARB	California Air Resources Board
CEQA	California Environmental Quality Act
CFR	Code of Federal Regulations
CPUC	California Public Utilities Commission
CCR	California Code of Regulations
Division	Department of Conservation, Division of Oil, Gas, and Geothermal
DOGGR	Department of Conservation, Division of Oil, Gas, and Geothermal
ERP	Emergency Response Plan
FERC	Federal Energy Regulatory Commission
Legislature	Legislature of the State of California
National Labs	Lawrence Berkeley, Lawrence Livermore, and Sandia National Laboratories
OSHA	Occupational Safety and Health Administration
PAL	Project Approval Letter
PHMSA	Pipeline and Hazardous Materials Safety Administration
PRC	Public Resources Code
RMP	Risk Management Plan
UIC	Underground Injection Control
UGS	Underground Gas Storage
ZEI	Zone of Endangering Influence

GENERAL COMMENTS

0001-1

Items included in the proposed regulations were defined as provisions aimed at preventing leaks rather than responding to them, and include construction standards, mechanical integrity tests, emergency response, data requirements, monitoring and inspection requirements. What is being addressed is integrity, not safety. Safety analysis includes looking at possible risks and assessing probability of occurrence and the ability of the design to accommodate these risks.

Response: ACCEPTED. Requirements for risk analysis and a project-specific RMP form the core of these proposed regulations. Thus, the regulations do not solely focus on safety, requiring operators to do extensive risk analysis including quantitative assessment of the probability and potential intensity of harm which may result from

every aspect of operations. The RMP requirements of section 1726.3 provide for the expanded risk analysis commenter recommends.

0015-11, 0052-2

As these proposed regulations are new, performance indicators should be identified and assessed, and the regulations themselves should be assessed, to determine if desired outcomes are being achieved. If desired outcomes are not being achieved, adjustments to the regulations should be made within one year of the assessment. Recommended review schedules include once every three-months for a 24-month period or between one year and eighteen months after adoption.

Response: ACCEPTED IN PART. *The Division regularly reviews its regulations for effectiveness and determines when updates are needed to achieve regulatory goals. In the case of new regulations, especially extensive and complex regulations, which include development of plans that are new to the Division (such as the RMP), the regulations will be continuously evaluated for effectiveness as the Division works with and enforces the requirements. The National Labs have also recommended that the Division seek peer review of its regulations by other qualified agencies or a stakeholder group. The Division is exploring ways to implement this recommendation.*

0020-1

Natural gas storage is essential to providing reliable gas deliveries and pricing throughout seasonal and daily demand fluctuations, electrical grid shutdowns and maintenance, and natural disasters.

Response: NOTED. *Thank you for your comment.*

0021-8

Many of the fault and earthquake issues and questions at the Aliso Canyon gas storage field could have been avoided if standard seismic and fault hazard siting requirements had been in place in the 1970s.

Response: NOT ACCEPTED. *Science continues to develop daily in its ability to identify and trace faults, determine causes, and identify potential harms from earthquakes that cannot yet be predicted. Many faults are only now being identified and mapped, and it has become clear that much of California's infrastructure is built in hazardous faulting areas, a larger systemic problem not unique to gas storage facilities.*

0030-71

Storage operators must become much more transparent and publicly accountable. The operators must begin to inculcate a “safety culture” within their decision-making structures.

Response: NOT ACCEPTED. *The role of the Division is to set regulatory requirements for the safe operation of UGS wells. Culture management and community relations efforts are part of the internal management of an organization and not a proper subject of the proposed regulations.*

0030-63

If the agencies truly want to protect Californian’s health and environment rather than the oil industry, they must issue a moratorium on acid treatments until more information is known about the chemicals used, and an analysis conducted to determine if there are safer, less toxic alternatives.

0030-76

The regulations must immediately prohibit all well stimulation activities in all gas storage wells.

Response to comments 0030-63 and 0030-76: NOT ACCEPTED. *Any use of well stimulation treatment on a gas storage well would be carefully evaluated by the Division, but PRC section 3160, subdivision (o), specifically contemplates the possibility of well stimulation treatments used for routine maintenance of gas storage wells.*

ACTIONS NEEDED BEFORE REGULATION IMPLEMENTATION

0017-9

The Aliso Canyon facility should be in compliance with all of the proposed regulations, including the RMP requirements, prior to DOGGR approving any new injection. The current RMP covers multiple UGS facilities, despite the statement from DOGGR that individual RMPs would be more effective.

0017-10

Each well at Aliso Canyon should be evaluated for having a subsurface safety valve using the factors listed in the proposed regulations section 1726.3(c)(2), including geologic hazards, prior to DOGGR approving any new injection.

Response to 0017-9 and 0017-10: NOT ACCEPTED. *The Legislature, California Public Utilities Commission (CPUC), California Air Resources Board (CARB), and the Division are working together on the ongoing response to the Aliso Canyon incident. For its part, the Division has conducted a comprehensive safety review of all the wells at the Aliso Canyon facility and has shut-in all wells that failed the required testing. Evaluations, testing, and remediation continue. Like all UGS operations, the Aliso Canyon facility must be brought into compliance with the new regulations on the schedule provided for in the proposed regulatory text.*

0027-31

The regulations should seek greater compatibility with the aims of the Safe Drinking Water Act with explicit studies of the underlying geological areas. DOGGR needs to examine further characteristics of geological areas near all gas storage facilities. The current approach creates the illusion that safety is being considered while allowing injection activity to continue, but the distinctions are far too gross to provide any real reassurance. Because protection of the public cannot be assured without more particularized study, approval of these regulations should not be done until the studies are complete.

Response: ACCEPTED IN PART. *The proposed data requirements include extensive information regarding underlying geological areas. Information contained within those geologic studies will inform the Division and the operator, but is unlikely to affect the proposed regulations that require risk hazard and assessment, including geologic analysis. Delaying approval of the proposed regulations allows existing gas storage operations to continue without meeting these new requirements. A delay for geologic analysis would delay the implementation of a more robust regulatory framework.*

0030-34

At the outset, DOGGR should require that operators immediately cease all injection, and conduct a thorough investigation of the integrity of all gas storage wells in the state. Any wells with a single barrier and no safety valve must immediately be pressure isolated from the underground storage aquifer and undergo inspection using best available technology to search for evidence of corrosion, cracking, or other loss of integrity. If any such evidence is found, the well must be taken out of operation immediately, and reworked to add cement casing. If the well does not have a subsurface functioning safety valve, it must immediately be plugged to the base.

0030-56

First and foremost DOGGR must issue an immediate moratorium on all gas injection until DOGGR has: implemented a permanent ban on all injection into gas storage wells above fracture gradient; completed a root cause analysis of the leak at Standard Sesnon 25 (SS-25); delineated clear best management practices (BMPs) and best available control technology (BACT) for all construction, conversion, operation and maintenance of gas storage wells; conducted an audit of all gas storage wells to ensure they meet BMPs and BACT; identified and inspected all gas storage wells that have only one pressurized casing without surrounding cement, and either isolate, inspect, or add cement; identified all gas storage wells that do not have subsurface safety valves, plugged them to their base; approved an RMP for each gas storage field which takes into consideration the results of the root cause analysis of SS-25 and require a root cause analysis be performed for every accident or near-accident; and ensure that the appropriate state or local air district or board has developed protocols and implemented a program of continuous monitoring for all potential air pollution caused by gas injection operations, including but not limited to, methane, VOCs including BTEX (benzene, toluene, ethylbenzene and xylenes), metals, hydrogen sulfide, and polycyclic aromatic hydrocarbons. These protocols must be incorporated into any gas storage regulations if they are to have any effect on the safety and environment.

Response to 0030-34 and 0030-56: NOT ACCEPTED. While the Division has the authority to impose remedial requirements as needed to prevent damage to life, health, property, and natural resources, that does not extend to banning all injection at all locations. Under the proposed regulations, operators will be required to thoroughly test and inspect each gas storage well, to conform to rigorous new construction requirements for gas storage wells, and prepare a detailed risk management plan for each underground gas storage facility. Existing wells that are not in compliance with the new construction standards will be corrected over time based on level of risk, in accordance with a work plan approved by the Division as part of the operator's RMP. Availability of equipment and personnel makes a single deadline requirement for all wells to meet the new well construction standards unreasonable and impracticable to implement.

0046-2

This whole regulatory process is just a rushed attempt to continue to provide cover and a notion of safety to gas storage operators. It needs to stop so that assessments can be made. Specifically, an Environmental Impact Report and seismic risk analysis for each existing facility. Every operator at each storage facility must provide disclosure, which

would then be the basis of a health risk assessment. Only when these assessments have been performed will it be possible to determine the appropriate regulations.

Response: *NOT ACCEPTED. Building upon the emergency regulations in place for underground gas storage facilities, the proposed regulations address a more complete regulatory scheme tailored specifically to underground gas storage facilities and gas storage wells. The proposed regulations also provide necessary clarifications and specificity to implement the statutory requirements of SB 887. The proposed regulations include new or revised well construction requirements for gas storage, rigorous testing and monitoring requirements for gas storage wells and underground gas storage facilities, and requirements for developing and maintaining risk management plans for underground gas storage facilities. If further study or experience indicate a need for additional requirements within the scope of the Division's authorities, then subsequent rulemaking action may be taken.*

APPROVALS AND ENFORCEMENT

0015-2

The Division must implement a formal permit, compliance, violation, and penalty system as the review of records of gas storage operations failures has demonstrated falsifying of past designs and changing designs and operations without prior Division approvals.

Response: *ACCEPTED IN PART. This rulemaking action adds section 1726.2, which addresses Division approval of an underground gas storage project, including ongoing review for compliance with the conditions of approval. The Division has a number of statutory enforcement authorities, but implementation of those statutory authorities is outside the scope of this rulemaking action.*

0024-8, 0026-4

The Division approval requirement for the various plans required under the proposed regulations should be eliminated. As with other regulations, operators will be responsible for complying with the final version of proposed regulations. These proposed regulations set forth with detail the expectations and contents required for such plans. Further the Division can already impose consequences on operators for failing to comply with the proposed regulations. In this case, requiring Division "approval" introduces a requirement in this instance that may only serve to impair an operator's ability to implement the proposed plans in a timely manner. Finally, each operator should be able to determine its own business practices necessary for implementing a management plan that meets the requirements and specifications set

forth in the proposed regulations without having to secure approvals from the Division to do so.

Response: *ACCEPTED IN PART. The Records Management Plan section 1726.4.2 has been modified so that operators must still have a plan but Division approval is not required. The Division will still review the plan and order operators to correct and improve plans that do not meet regulatory requirements.*

NOT ACCEPTED. PRC section 3181 specifically requires operators to submit an RMP and its constituent plans to the Division for approval. In addition, because the proposed regulations use a structure of default requirement with performance standards and approved variance based on risk assessment, there are many options the operator may consider which will require specific approval by the Division. As the RMP will be the blueprint for safe operations going forward, the Division must ensure that the plan is sufficient to meet the regulatory requirements to prevent damage to life, health, property, natural resources, and the environment.

0024-14

Commenter recognizes the authority of the Division over storage well integrity and safety and understands that any plans and procedures developed will be subject to inspection by the Division. Many of the references to the authority of the Division are unnecessary in the proposed regulatory language, and should be removed.

Response: *NOT ACCEPTED. After each section of the proposed regulations, an authority section is provided which identifies the statutory authority for the promulgation of the regulation and the code sections that are being interpreted or referenced. A regulation is not valid unless the agency has the authority to promulgate regulations and the regulation is consistent the statute that is interpreted or applied. The inclusion of these authority statements has become common practice as they provide important information that allows for the cross-referencing of regulations and statutes.*

0027-8

In the public meeting, DOGGR said that these regulations are intended to create consistency. This is not possible given the degree of discretion afforded. Where the regulations provide the Division with broad discretion in determining which standards operators must adhere to, it is difficult for the public to hold operators accountable and prevents transparency and consistency in the records.

Response: *NOT ACCEPTED. Prior to the passage of SB 887 in 2016, UGS projects were regulated under the Underground Injection Control Program (UIC) and did not*

have a dedicated set of regulations. These proposed regulations are focused on UGS facilities, and implement the goals of SB 887 and build upon the emergency regulations by creating consistent requirements across UGS operations. Consistency does not require sameness however, and the proposed regulations recognize that public health and safety can only be successfully protected when site-specific geology and proximity to human activities are considered. The proposed regulations create a consistent framework for operator compliance with a RMP that must use hazard identification and quantitative risk assessment to determine how they will ensure the safety of well operations. Where the Division has discretion to determine if the operator has met performance standards, it will document in the well file the evidence used to prove that standards have been met.

0027-16

The proposed regulations should state that misreporting the presence of a functional subsurface safety valve will result in treble damages for any blowouts.

0027-28, 0049-2

Action should be taken to make these companies face consequences for their actions and take responsibility for the problems they have caused. That is one thing missing from these comprehensive regulations – consequences. If a company is doing some wrong, action should be taken so the wrong is not allowed to continue. In order to have a deterrent effect, DOGGR should include civil penalties that are significant enough so that there may be no short term or long term calculation in which an operator may decide to pay the maximum civil penalty as a cost of doing business. The proposed regulations are currently silent on penalties.

0030-64

DOGGR must be able to issue fines for failure to report or inaccurate reporting of data.

Response to 0027-16, 0027-28, 0030-64, 0049-2: NOT ACCEPTED. The Division's authority to issue civil penalties for violations of statute or regulation is found in PRC section 3236.5, which includes limitations and considerations for determining the amount of a civil penalty.

0027-32

The regulations should expressly incentivize enforcement by private attorneys general.

Response: *NOT ACCEPTED. It is up to the Legislature to identify those instances where private attorneys general are appropriate by incorporating a specific provision in statute.*

0030-3

DOGGR's failure to enforce regulations has resulted in significant risks. The regulations need to clarify DOGGR's enforcement authority with respect to its requirements; for instance, what will happen if a facility fails to complete an RMP? Or comply with its RMP protocols? Clarifying when and how DOGGR will take enforcement action is critical to ensuring the effectiveness of these regulations. First, such clarity helps the regulated operators understand exactly when and under what conditions it may be subject to penalties or enforcement action. Second, these regulations will only be as strong as DOGGR's enforcement.

Response: *NOT ACCEPTED. The Division has a number of statutory enforcement authorities, but implementation of those statutory authorities is outside the scope of this rulemaking action.*

0037-1

If I'm a driver, I can't retroactively apply for a license. If I'm building a house, I can't retroactively apply for a permit. So how is it that gas storage operators can retroactively apply for a permit? If there's a mishap the permit should be rescinded and the operation cease to exist.

Response: *NOT ACCEPTED. This rulemaking action adds section 1726.2, which addresses Division approval of an underground gas storage project, including ongoing review for compliance with the conditions of approval. The Division has a number of statutory enforcement authorities, but implementation of those statutory authorities is outside the scope of this rulemaking action.*

CONSULTATION WITH OTHER AGENCIES & GUIDANCE DOCUMENTS

0010-1

Commenter recommends that DOGGR consult the Interstate Oil and Gas Compact Commission and the Ground Water Protection Council's "Underground Gas Storage Regulatory Considerations," a guide published in May 2017 (Regulatory Considerations guide), designed to help state and federal regulators updating their gas storage programs. DOGGR staff participated heavily in the production of the guide, and so commenter hopes these considerations strike DOGGR as both familiar and reasonable.

Response: *ACCEPTED.* The referenced document introduces the important concept of RMPs with a focus on the need to prevent migration of stored gas out of the storage zone to protect human health and the environment. It identifies the need to create well construction standards using multiple barriers and the importance of ensuring well and reservoir integrity during operations. It also discusses the need for monitoring or observation wells, the vital safety role of well control mechanisms at the wellhead, and issues related to abandonment, well closure, and restoration. The Division believes the proposed regulations are consistent with the recommendations of the Regulatory Considerations guide.

0020-2, 0024-12

Any regulations adopted by California must be consistent with the Pipeline and Hazardous Materials Safety Administration (PHMSA) rule and guidance in the American Petroleum Institute Recommended Practice (API RP) 1170 and 1171, including PHMSA's published Underground Natural Gas Storage FAQs. Commenters encourage the Division to communicate and consult with the CPUC, PHMSA, and CARB to ensure that there will be no conflicting or overlapping regulations. For example, the proposed regulations include language directing an operator to evaluate the cost-effectiveness of risk prevention protocols. While commenter appreciates the need for this evaluation, it is already underway at the CPUC through the Risk Assessment Mitigation Phase filing. Commenters recommend avoiding duplication of this effort in the Division regulation. Federal minimum standards (per the PIPES Act of 2016) are still forthcoming. Commenters urge the Division to consult closely with PHMSA to ensure no inconsistencies in the requirements.

Response: *ACCEPTED IN PART.* The proposed regulations are consistent with and are more stringent and comprehensive than the minimum federal standards. The Division consulted API RP 1171 as a starting point in developing the proposed regulations. (Recommended Practice 1170 was not consulted because there are no solution-mined salt caverns used for natural gas storage in California). The Division's proposed regulations would include additional detail and definition as to requirements in comparison to API RP 1171, which tends to apply requirements based on more open-ended case-by-case assessments. Examples of greater definition and stringency in the Division's proposed regulations include more stringent and defined well construction standards, a clear regulatory framework for risk management planning, more detailed requirements for mechanical integrity testing and monitoring, more frequent testing of safety valves, and stronger Division oversight through project data requirements.

PHMSA's January 18, 2017 Interim Final Rule establishing minimum standards for underground natural gas storage facilities addresses many of the same issues as the Division's proposed regulations. Both sets of regulations are intended to minimize the environmental and public health risks associated with such facilities. However, PHMSA's minimum standards only provide a floor for regulation of underground gas storage projects, and the Division's proposed regulations are necessary to achieve greater protection of health and safety and to meet statutory requirements for underground gas storage projects under state law.

0020-3, 0024-13, 0026-2

Recommendations from the Aliso Canyon natural gas task force and Federal minimum standards (per the PIPES Act of 2016) are still forthcoming. In the interim, the Division should utilize the risk-informed, performance-based processes described in and adopt the consensus standards of API RP 1170 and API RP 1171 by reference. API RP 1171 requires operators to develop RMPs to appropriately address the threats, operating parameters, and risks at each specific well and facility. The final DOGGR regulations should require operators to develop RMPs that continuously drive risk reduction and ensure that resources are expended in a timely and efficient manner, with focus on the wells that present the highest risk. This standard is the product of historical knowledge and experience of those who understand how underground storage facilities function.

Response: *ACCEPTED IN PART. API RP 1170 applies to UGS facilities in solution-mined salt caverns, which do not exist in California. Thus, it is not appropriate to include it in the proposed regulations, which are focused on intrastate gas storage facilities in depleted hydrocarbon reservoirs. API RP 1171 was generally used as the basis for the proposed regulations and many of its requirements, including the need to develop RMPs have been included. However, as a guideline document, it does not contain specific requirements appropriate for enforcement. Thus, the Division has used the risk-based standards and approach of API RP 1171, but has made some portions mandatory and added requirements where needed to achieve statutory mandates.*

0026-1

Commenter recommends that the Division consider standardizing terms and usage set forth in Section 1726 to be consistent with API RP 1171, "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs" and PHMSA's Interim Final Rule, "Safety of Underground Natural Gas Storage Facilities Interim Final Rule" (81 Fed. Reg. 91,860, Dec. 19, 2016, Docket No. PHMSA-2016-0016.) Consistent terms and terminology promote common understanding, implementation, and avoids confusion or inconsistency across regulations and

requirements. API 1171 and PHMSA's Interim Final Rule set forth industry standard and specific terminology, which is the product of the historical knowledge and experience of both operators and regulators in the underground storage realm.

Response: *NOT ACCEPTED. The Division used API 1171 as the basis for the proposed regulations, including use of same or similar terminology. However, the Division also worked to ensure that the proposed regulations' language is consistent with existing regulatory language, as well as industry usage in California. The Division believes it has achieved a balance between these two competing interests while remaining focused on clarity. Without any additional information regarding those specific terms that commenter may find confusing, the Division is unable to consider any specific changes to the regulatory text in response to this comment.*

IMPACTS & COSTS

0024-4

Gas storage facilities are essential to ensure the reliability of gas service to customers. As currently proposed, the timing for performing the prescribed well testing and installation of tubing and packer will be logistically challenging and may impact reliability. The proposed regulations will necessitate taking wells out of service for significant periods of time, thereby severely limiting the ability to inject or withdraw from the storage facility to meet system reliability needs. In addition, the nature of this work simultaneously being conducted across all storage facilities in California may impact operators' ability to perform this work in a timely manner for drilling and maintenance activities. Limited industry resources may further extend the timing of the outages and impair the ability to provide reliable service.

Response: *ACCEPTED IN PART. Requirements for well construction implementation have been phased so that an operator may bring a percentage of their wells into compliance each year rather than having to comply all at once. Many operators have already begun to bring their wells into compliance in anticipation of the regulations. NOT ACCEPTED. Integrity testing requirements are cyclical with a minimum requirement for an initial test within 24 months. This testing will need to be phased by operators to ensure that all wells are tested within the appropriate timeframe, but that testing does not need to happen all at the same time across the state. The 24-month timeframe for completion of testing requirements should insure that limited industry resources are not a barrier to compliance.*

0024-6

Initial costs to comply with the proposed regulations will be \$209,300,000 with annual reoccurring costs of \$109,600,000. The initial costs are based on the requirements to install tubing and packer assemblies in all wells, drill 24 new wells to offset production loss (due to tubing and packer installations and biennial testing) and install enhanced corrosion monitoring systems. The annual cost includes temperature and noise logs, 50% of all wells pressure tested and wall thickness logs conducted, produced water and gas quality monitoring, and daily leak surveys. These costs are incremental to the costs commenter currently recovers in rates from its customers. In order to recover its costs to comply with these new regulations, commenter would need to seek recovery through the CPUC ratemaking process and therefore request that the Division acknowledge the need for operators to recover the significant costs to comply with the new regulations, and allow suitable time prior to implementation for the operators to seek adequate cost recovery mechanisms.

0031-4

Additional consideration is required relating to the likely cost to ratepayers of multiple well re-abandonments, needs for numbers of new gas storage wells (to ensure adequate deliverability) and for impacts of higher frequencies of testing (which may not be practical when adjacent to residential or urban areas).

0031-5

Ultimately, these regulations as written will cause a loss of jobs, tax revenue, and energy system reliability, if gas storage facilities are either relocated out of state – or abandoned in favor of alternate gas supply methods, such as via LNG terminals or pipelines.

0049-1

People want to get out of neighborhoods that are being affected by gas storage facilities due to “a black hole of health defects”. This could create a huge economic upset as property values and other issues are affected down the line.

Response to 0024-6, 0031-4, 0031-5, 0049-1: ACKNOWLEDGED. The Division has considered the potential economic impacts based on the proposed regulations and has done its best to balance the need for risk mitigation and safety with the need to keep cost burdens low. However, as the Aliso Canyon incident demonstrates, there can be no substitute for regular inspections, monitoring, and testing, which can reveal a problem before it becomes a major health and safety risk. The Division acknowledges that there may be a minor increase in the price of natural gas and electricity for

consumers and believes the Legislature took that increased cost into account when passing SB 887 requiring the Division to promulgate these regulations.

0024-33

§1726.3(c)(4): Operator's cost to install and monitor sample ports at each wellhead: for 115 wells, cost per install is \$95,000 for a total install cost of \$10,925,000. Annual cost to monitor sample ports is \$1,000,000.

Response: *ACKNOWLEDGED. The Division has done its best to meet statutory requirements and regulatory goals without excessive cost burden to operators.*

IMPLEMENTATION TIMING & TIMEFRAMES

0015-10, 0017-1, 0052-1

Some parts of the regulations lack a timeframe for implementation so follow-through is likely to be slower than otherwise. Commenters recommend that RMPs, Emergency Response Plans (ERPs), and project data requirements, including casing diagrams and records management programs, be required from operators within three months of the adoption of these regulations.

Response: *ACCEPTED IN PART. Timeframes have been added for the submission of the RMP (6 months from effective date), which includes the ERP, and project data requirements (90 days from effective date). Where plans are already in existence under the emergency regulations, no implementation timeframe is needed.*

0020-5, 0022-1, 0024-2

Commenters support the flexible risk-based approach to certain compliance activities that has been added to the proposed regulations as a reasonable and appropriate means of accounting for project-specific characteristics. This approach appropriately allows operators to identify potential risks associated with individual projects and wells, and then tailor testing methodology and frequency plans specifically to address such risks, thereby achieving State and operator safety goals. Commenters appreciate the flexibility in the proposed draft for operators to develop an implementation timeframe based on risk assessment findings and recommend a phased approach for operators to implement the necessary testing effectively and meet the requirements efficiently.

Response: *ACCEPTED IN PART. Phased implementation has been provided, however, it is not open-ended or purely based on risk assessment. Some requirements, such as the submission of RMPs, have hard deadlines for compliance. Other*

requirements, such as well construction requirements for existing wells, may be phased based on risk assessment, provided that a minimum percentage of non-compliant wells are addressed annually. Thus, although commenters are correct that a risk-based, phased implementation process has been provided, it is not the open-ended, exclusively risk-based, assessment-driven process they describe.

0026-3

Commenter proposes a nine to twelve-month implementation period prior to the revised regulations becoming effective. This period may be required for the development, submittal, approval and implementation of standards and procedures for the required plans including risk management, records management and emergency response. Commenter assumes that the proposed implementation period would not apply to well construction activities. Additionally, commenter suggests a mechanism be created to allow for operators to request an extension of such implementation period that may be granted by the Division upon a showing of good cause for the extension.

Response: ACCEPTED IN PART. *The need for an implementation period for current operators is recognized and has been added section by section where appropriate. For example, the RMP will be due within six months of the effective date of the new regulations.*

NOT ACCEPTED. *A blanket delay for implementation is just a delay in the effect of the regulations, which is not appropriate under the statutory mandate. Extensions are not permitted under the regulations; where a violation occurs, the Division will work with the operator to achieve compliance as quickly as possible without sacrificing the health and safety goals of these regulations. Civil penalties or other consequences of non-compliance will be determined based on the circumstances of the violation.*

PUBLIC NOTICE AND DISCLOSURE

0015-55

The documents that can be reviewed over the internet are not adequate. In a case where known changes were made to the use and configuration of a well, commenter was unable to determine what was going on.

Response: *The documents available on the internet are the documents the Division and the operator use to communicate with each other about wells and well operations. These documents are posted so that the public can monitor the activities in which the Division engages. Generally, records and data received and approved by the Division to comply with statutory requirements are posted to the Division's public website.*

0027-2, 0030-75

DOGGR's regulations do not require notice to any residents when oil companies start construction or repairs at their UGS facilities or where there are changes to injection permits. Members of the public should not have to go well by well on the DOGGR website searching for information about repairs, valves, injection pressures, and safety. DOGGR should be providing notice to residents whose homes may be impacted by these activities before it issues any permits. The determination of who gets notice should be based upon the likely migration of gas or oil into the community using (1) established wind patterns; and (2) underground layers (strata) where gas or oil may migrate. All potentially impacted residents should be notified before permits are issued. At a minimum, this includes all residents within five miles (the area of impact according to the Department of Public Health). PALs should be posted online for public comment.

Response: *NOT ACCEPTED. Public notice is a detailed process which requires notice to be sent to a list of interested persons with a specific period for comments and comment response. This delay is unreasonable for the majority of constructions, repairs, and conversions of gas storage wells and could create additional hazards due to delay. The information requested by commenters is available as part of the well file and will continue to be collected as part of the data requirements under the proposed regulations. Creating a public notice requirement for every change to every well when the data to be released will be the same every time is not cost-effective and does not appear to create any additional benefit to public health and safety.*

0027-3, 0027-5, 0041-2

The proposed regulations do not force operators to make important disclosures to the community including, but not limited to the following: disclosure of all chemicals/fluids injected underground with no trade secret bars; disclosure of all chemicals/fluids withdrawn with no trade secret bars; disclosure of all emissions from operations including emissions from turbines; disclosure of all chemical reactions at facility between chemicals used (while chemical composition is considered for its effect on casing in sections 1726.5(b)(4) and 1726.3(c)(4)(A), the regulations do not address all chemical reactions and their effect on operations and emissions); disclosure of all data about injections, withdrawals, etc.; and penalties for violating disclosure and reporting requirements.

Response: *NOT ACCEPTED. The natural gas injected into and withdrawn from a gas storage reservoir is high quality, processed, commercial gas from producers outside the*

state. As such, its contents and chemical make-up are generally known, as it has been processed and odorized prior to transport under federal law.

0030-33, 0038-1

Public disclosure of well records is essential to provide California residents with full access to information that impacts public health and welfare. Commenters recommend amending the regulations to ensure that all well records and data submitted or received for gas storage projects under section 1726.4 or any other section of this chapter, must be made available to the public online. In fact, SB 887 requires it.

Response: NOT ACCEPTED. *All records received by the Division are posted online to the website or the well file database unless specifically covered by a law requiring confidential treatment. Language in the regulations is not needed to effectuate this posting, which is already expressly required under PRC section 3187.*

SHUT THESE FACILITIES DOWN PERMANENTLY

0001-2, 0005-1, 0007-1, 0011-1, 0013-1, 0016-1, 0028-1, 0034-1, 0036-1, 0037-2, 0038-3, 0041-1, 0042-1, 0043-1, 0044-2, 0047-1

Commenters demand the immediate and permanent shut down of all UGS operations in the State of California. No regulations will make communities safe from dangerous gas facilities. Hazardous seismic activity is statistically guaranteed to lead to serious accident, and the known and unknown community health impacts associated with ongoing operations are unacceptable. The only way to prevent leaks and protect public health and the environment is to shut these facilities down. Additional concerns include fire danger, oversight failures, age of wells, environmental pollution, proximity to populated areas, and ongoing leaks from the Aliso Canyon facility. The gas companies are bad faith actors who do not care about following the rules; turning communities into “sacrifice zones” and manipulating government agencies, who should do the “job you are entrusted to do” for the people and not the gas/oil industry. Our resources should be focused on renewables and alternatives, not continuing to use this dirty energy that hurts us and kills us. Regulations aren’t going to stop gas from leaking out of every nook and cranny in the infrastructure of all gas industry. The moral and ethical position is clear – shut these facilities down.

0004-1, 0009-1, 0014-1, 0029-1, 0046-1

There have been severe negative health impacts associated with the Aliso Canyon storage facility and the blowout. Families have been relocated from homes where they have resided for more than 30 years; nearby residents are suffering from headaches,

nausea, nose bleeds, skin rashes, eye irritation, sneezing, coughing, sleepless nights, anxiety, and depression. Commenters believe the facility had leaks long before the blowout, the fence line monitoring system continues to show high levels of contaminants with daily spikes, and health studies which support that the negative impacts are ongoing. Community members must regularly evacuate, keep bottled oxygen available, and make regular trips to the ER. Commenters are concerned about the impact on our children and pets; the only way to stop the harm is to move away or shut this facility down. The proposed regulations are insufficient to protect the community. Add the threats of fire and earthquakes, and nothing short of shutting this facility down is acceptable!

Response to comments 0001-2, 0005-1, 0007-1, 0011-1, 0013-1, 0016-1, 0028-1, 0034-1, 0036-1, 0037-2, 0038-3, 0041-1, 0042-1, 0043-1, 0044-2, 0047-1 and 0004-1, 0009-1, 0014-1, 0029-1, 0046-1:

NOT ACCEPTED. The Division is cognizant of the risks associated with UGS facilities and is compassionate towards those community members who may have been affected. While the Division has the authority to impose remedial requirements as needed to prevent damage to life, health, property, and natural resources, that does not extend to banning all injection at all locations. Building upon the emergency regulations in place for underground gas storage facilities, the proposed regulations address a more complete regulatory scheme tailored specifically to underground gas storage facilities and gas storage wells. The proposed regulations also provide necessary clarifications and specificity to implement the statutory requirements of SB 887. In essence, the proposed regulations include new or revised well construction requirements for gas storage, rigorous testing and monitoring requirements for gas storage wells and underground gas storage facilities as a whole, and requirements for developing and maintaining risk management plans for underground gas storage facilities. If further study or experience indicate a need for additional requirements within the scope of the Division's authorities, then subsequent rulemaking action may be taken.

0005-2, 0006-1

The Aliso Canyon facility leaks every day and is immediately adjacent to thousands of homes and residents. We are approaching two years with this facility closed and there have been no adverse effects on energy reliability. Independent studies by reputable firms have confirmed that this facility is not necessary for energy reliability. Recent newspaper articles reported that CAISO has sold excess power to Arizona (and other states?), to avoid an overload on the transmission lines (e.g. <http://www.latimes.com/projects/la-fi-electricity-solar/>). Clearly, there's no need for emergency power generation using gas from Aliso Canyon. Leave that facility shut

down until (if ever) it can be shown to have no risk of further leaks into the surrounding community.

0033-1, 0045-1

We need an energy source but we don't need natural gas. We need a clear, reliable energy source, and that is found in wind and solar. There are countless examples of various countries operating on wind and solar technology and using wind and solar energy sources and exceeding their needs. A VP of Sempra Energy said a few months ago that there's no technical impediment to getting to 100 percent renewable. Profits is all that is standing in our way. Let's shut these facilities down.

0048-1

There is a huge aging infrastructure problem with energy security. These wells date back to the 30's and 40's and are affecting public health today. Leaking of benzene and methane, air pollution, explosive hazards, earthquake damage. The logistics of these storage facilities and natural gas fracking will bring extreme economic health and energy security cutbacks. Why perpetuate a system that's broken? And by system, I mean oil wells that have exceeded their expiration date years ago.

0027-1, 0038-2, 0040-1

The proposed regulations continue to protect oil and gas companies from liability and undermine public scrutiny of illegal and/or inadequate operations. These regulations must be modified to protect the rights of families in the San Fernando Valley. Please think of us first as a community, as lives that matter. Think about your family being affected or dying. We've been poisoned for years.

0044-1

Community safety and environmental sustainability should be at the forefront of thought processes when thinking of approving projects or proposing them. Environmental justice should also be at the forefront.

Response to comments 0005-2, 0006-1, 0027-1, 0033-1, 0038-2, 0040-1, 0044-1, 0045-1, 0048-1: NOT ACCEPTED. Building upon the emergency regulations in place for UGS facilities, the proposed regulations address a more complete regulatory scheme tailored specifically to UGS facilities and gas storage wells. The proposed regulations also provide necessary clarifications and specificity to implement the statutory requirements of SB 887. The broad objectives of the proposed regulations are to establish:

- *A comprehensive regulatory framework tailored to the regulatory concerns specific to UGS projects*
- *Well construction standards for gas storage wells*
- *Mechanical integrity testing requirements specific to gas storage wells*
- *Standards and specifications for risk management plans for UGS projects*
- *Standards and specifications for emergency response plans for UGS projects to ensure rapid and safe responses when emergency situations arise*
- *Standards and specifications for UGS project data requirements, including protocols for operators' retention and management of records*
- *Monitoring and inspection requirements for gas storage wells or the UGS project as a whole to ensure early detection of any indication of integrity concerns*
- *Standards and specifications for the inspection, testing, and maintenance of wellheads and valves*
- *Protocols for the decommissioning of a UGS project*
- *Implement the well reporting and response requirements or PRC sections 3183 and 3184*

The proposed regulations will further the statutory mandates and goals for UGS projects; reduce risks to health, safety and the environment; and facilitate thorough and transparent oversight, evaluation, and risk assessment of UGS projects.

SITING CONCERNS

0010-35, 0015-12, 0030-1, 0046-5, 0051-1, 0052-3

Natural gas facilities have a significant history of acute dangers. Emissions hazards are a risk to residents and school children, as well as to our climate. Safety failures including poor quality control and inadequate inspection, as well as inadequate oversight, planning and response have led the Legislature to pass several laws encouraging operators to make safety a priority. Regulatory enforcement failures contribute to the problem and the advanced age of oil infrastructure exacerbates the likelihood of structural integrity issues. Lack of information regarding field activities and chemical emissions puts the public and the environment at risk. Thus, a definition for "buffer zone" should be included with a requirement for a significant buffer zone between these facilities and nearby sensitive receptors or natural resources. Proximity to people should be one criteria considered. According to the California Council on Science and Technology a half-mile is considered a science-based health and safety buffer around oil and gas facilities. This analysis was performed on general well

stimulation, fracking, acidizing, and drilling. We need an analysis to determine what is the proper science-based buffer for gas storage facilities as part of an EIR.

0050-1

The government has issued two permits – one an industrial permit to the operator of the gas storage facility, and one to the builder who developed the residential area nearby. How can these two incompatible uses be permitted in the same area? There are serious health impacts on me and my neighbors' health, I'm concerned about the poor communication and attention to detail by the gas company during the Aliso Canyon evacuation, and believe that measuring the air quality is an insufficient response to protect public health.

Response to 0010-35, 0015-12, 0030-1, 0046-5, 0050-1, 0051-1, 0052-3: NOT ACCEPTED. *The proposed regulations require a RMP for each UGS facility that includes evaluation of threats and hazards associated with operation of the underground gas storage project and identification of prevention and mitigation protocols that effectively address those threats and hazards. Consideration of proximity to people is inherent to the RMP process.*

0021-7

These new regulations lack requirements for the siting of new gas storage fields. Is DOGGR not expecting any new gas storage fields to be located in California?

Response: NOT ACCEPTED. *Permitting for a new intrastate UGS project is initially under the control of the CPUC and permitting for a new interstate UGS project is initially under the control of the Federal Energy Regulatory Commission. Once permitted by the CPUC or FERC, the operator would apply to the Division for project approval. This rulemaking action adds section 1726.2, which addresses Division approval of an underground gas storage project.*

0027-11

The proposed regulations mention data that must be submitted about the caprock, but nowhere is there any requirement that the geological location be of a type that prevents any escape of the gases to the surface. Petroleum reservoirs develop in a manner very different from natural gas reservoirs. Thus, storage of natural gas in former natural gas reservoirs adds a degree of public safety that does not exist when storing natural gas in old petroleum reservoirs.

Response: NOT ACCEPTED. The performance standards under the proposed regulations require that stored gas be confined to the approved zone of injection. Extensive geological data is required to demonstrate this confinement. The suggested requirement for geological containment of stored gas to prevent the escape of gas to the surface is already incorporated into the performance standards of the proposed regulations.

0046-4

Some of the UGS facilities are located in very high-risk fire zones. There have already been several fires at Aliso after the blowout. There have also been brush fire-type incidents. So what becomes too risky for these types of facilities?

Response: The proposed regulations require a Risk Management Plan for each UGS facility that includes evaluation of threats and hazards associated with operation of the underground gas storage project and identification prevention and mitigation protocols that effectively address those threats and hazards. Analysis and risk assessment of hazards associated with the potential for explosion or fire is expressly required.

SECTION BY SECTION COMMENTS

1726. PURPOSE, SCOPE AND APPLICABILITY

0027-10, 0030-74

§1726: This section mandates that “[u]nderground storage projects and gas storage wells are not subject to the requirements of sections 1724.6 through 1724.10.” This language releases underground storage projects and gas storage wells from adhering to the UIC regulations in those sections. Since the proposed regulations are new and untested, it is not proper to allow the fate and regulation of underground storage wells to go unchecked due to an oversight in drafting. To remedy this, the proposed regulation should include the language, “where Article 4 is silent, the UIC rules under sections 1724.6 through 1724.10 apply.”

Response: NOT ACCEPTED. The cyclical and seasonal nature of UGS operations means that injection wells in UGS projects are subject to different stresses and risks than injection wells used in oil and gas production. Thus, the UIC regulations currently in development for oil and gas injection activities are being developed for a different context and are not directly applicable to gas storage injection wells. UGS and UIC each have a dedicated program group at the Division that works with and develops these

regulations hand-in-hand with their on-the-ground experiences at storage and production facilities.

0015-3

These regulations must apply to all wells within the project Area of Review (AOR) or maximum horizontal extent of all zones which ever greater. (alt: “Horizontal delineation of a gas storage facility or its logical extensions”)

Response: *ACCEPTED IN PART. Language that limited requirements to “gas storage wells” has been removed so that all project wells must be in conformance. Language has also been added to require conformance with the well construction requirements by gas storage wells “and every other well that penetrates the gas storage reservoir.” The proposed regulations already require mechanical integrity demonstration for each well in the project and each well that intersects the reservoir used for gas storage, as well as casing diagrams required for all wells within the AOR or in the same or deeper zone as the storage reservoir.*

0020-4

One of the goals of the regulations should be to ensure that operators’ integrity management programs are effective and efficient in reducing risk and enhancing safety, while also minimizing impact to customers.

Response: *ACCEPTED. The Division agrees that this is a goal for the regulations and has done its best to balance safety and risk with reliability and cost.*

1726.1 DEFINITIONS

0019-6

§1726.1: It is unclear if the operator also means the owner or includes the owner. Additionally, in certain instances, operators refer to onsite personnel. The regulations should explicitly specify owner or operator. Alternatively, the regulations may provide a definition of operator and owner.

Response: *NOT ACCEPTED. The definition of operator is provided by PRC section 3009 and means “person who, by virtue of ownership, or under the authority of a lease or any other agreement, has the right to drill, operate, maintain, or control a well or production facility.”*

0021-1

§1726.1: New rules need to define active and potentially active faults. It is recommended that DOGGR consult with the State of California’s Geological Survey on such definitions.

Response: NOT ACCEPTED. The RMP includes the requirement to consider seismic hazards and faults. The terms active fault or potentially active fault are not used in the proposed regulation text, so no definition is needed.

0031-1

§1726.1: Where secondary and tertiary production of fluids occurs within boundaries of a gas storage field, definitions conflict with regulations concerning underground injection, without any indication which rules will supersede the others (§1720 and §§1724.6-1724.10 vs. §1726).

Response: NOT ACCEPTED. The proposed regulations specifically exempt UGS wells from the requirements of sections 1724.6-1724.10, providing clear direction as to which rules will apply. UGS wells defined as “critical wells” under section 1720 would clearly be subject to the requirements of sections 1724.3 and 1724.4 which prescribe specific well construction requirements for critical wells, in addition to the requirements applicable to a gas storage well.

0015-14

§1726.1(a)(1): The definition of “area of review” should include formations and pervious rocks. From within the modified definition, the terms “impervious and pervious”, “decrease and loss” and “hydrodynamic forces” should be further defined numerically and for gases, emulsions, suspensions, liquids, and slurries encountered in storage projects. Other recommended edits include the replacement of “means” with “must include”, “reservoir used for underground gas storage” with “underground storage project”.

Response: NOT ACCEPTED. Edits removing the reference to the “reservoir” in favor of the “project” are inconsistent with usage in the regulations. The inclusion of “formations” is duplicative; edits in response to other comments have removed the reference to impervious rock. The additional definitions recommended are not needed within the proposed regulations as the terms are used consistent with their ordinary meaning.

0025-2

§1726.1(a)(1): The AOR should delineate the area in which leakage from the approved storage zone could occur and be used to identify potential pathways by which injected

or displaced fluids could migrate out of the approved storage zone. It should take into account the entire geologic system used to store natural gas underground.

Response: *NOT ACCEPTED. Taking into account the entire geologic system could include the source of the hydrocarbon, which may be as much as 50-100 miles away. The AOR is properly focused on the area of direct project influence and includes evaluation of the potential for fluid migration. In addition, the assessment of the risk of fluid migration will be considered, and needed mitigation measures planned, as part of the RMP.*

0030-6

§1726.1(a)(1): Commenter supports a definition of AOR that is based on geologic features, but this alone is insufficient. The definition should be based, at a minimum, on a determined zone of endangering influence (ZEI) as well. (40 CFR §146.6) The ZEI includes consideration of the potential for fluid migration, including taking into account the presence of specific factors that can affect migration, including the pressures in the injection zone. In addition, the use of fracking and other well stimulation techniques, seismicity, and surface geological changes, must also be included as specific considerations when defining the AOR. The AOR was intended to determine whether the storage and injection of gas, fluids, or chemicals at various pressures have “a potential for contaminating underground sources of drinking water through wells, faults, or other pathways that penetrate an injection zone.” Recent studies have increasingly documented the risks caused by injection on seismicity, surface expressions and other geologic changes; and, gas, waste water, or oil leaking into the soil and air through idle or broken wells, and other potentially dangerous conditions. All of these conditions can, in turn, affect the size of, and impact on, the ZEI. Therefore, DOGGR must take a broad approach to developing criteria for AORs, and measure the AOR based on the ZEI rather than a fixed radius.

Response: *NOT ACCEPTED. The proposed definition for AOR includes the surrounding areas that may be subject to project influence and is focused on those geologic characteristics that would affect the potential for fluid migration. It is not a fixed radius, but a qualitative analysis of those areas that may be subject to influence from project operations including injection and well stimulation. In contrast, where the ZEI is used, it is calculated using a mathematical formula based on a site of injection, which may inadvertently exclude known impacts outside the calculated area.*

0010-42

§1726.1(a)(2): The word “caprock” should be replaced with the terms “confining strata” and “confining zone” throughout the proposed regulation. The definition of confining strata should be expanded to include lateral boundaries and lateral migration of fluids.

Response: *ACCEPTED. The term “caprock” has been changed to “confining strata” and includes all rock layer boundaries providing barriers preventing migration of fluids (the definition of “fluids” includes liquid or gas).*

0015-15

§1726.1(a)(2): The definition of “caprock” should be modified with the addition of all rock layer boundaries providing barriers preventing migration of gases, fluids and other mixes. From within the modified definition, further defining “boundary(ies)”, “barriers”, and “preventing” numerically and for gases, emulsions, suspensions, liquids, and slurries is needed.

Response: *ACCEPTED IN PART. The term “caprock” has been changed to “confining strata” and includes all rock layer boundaries providing barriers preventing migration of fluids (the definition of “fluids” includes liquid or gas).*

NOT ACCEPTED. The additional definitions that commenter would require are not needed within the proposed regulations as the terms are used consistent with their ordinary meaning.

0015-16

§1726.1(a)(3): The definition of “fluid” should include “liquid and/or gas” and be defined numerically and for gases, emulsions, suspensions, liquids, and slurries encountered in storage projects.

Response: *NOT ACCEPTED. A “fluid” can be in liquid or gas form. A mix that includes liquid and gas would still be a mix of fluids. The detail recommended by commenter is not needed when all fluids are included.*

0015-17

§1726.1(a)(4): The definition of “gas storage well” should include the injection or withdrawal of fluids as well as gases. Definitions should also be provided for “well” and “gas storage well” as all wells within the horizontal extent of the “area of influence”, “reservoir”, and “project”, specifically including all wells which influence pressures, temperatures, and volumes of the project.

Response: NOT ACCEPTED. It is not the intent of the Division to include waste water disposal wells in the definition of gas storage well, which would be the likely result of commenters recommendations. Wells such as observation wells and other wells that influence pressures, temperatures, and volumes are subject to the requirements without the need to add additional definitions. Sections 1726.5 and 1726.6 are clear that any well that penetrates the gas storage reservoir is subject to the mechanical integrity testing and well construction requirements established in this rulemaking action.

0024-15

§1726.1(a)(4): The definition for “gas storage well” as it pertains to idle wells should be modified to exclude the six-consecutive month requirement (as noted in PRC §3008(d)-(e)) as some gas storage wells are utilized only for withdrawal of gas to optimize utilization of the gas storage reservoir. Additionally, an operator may choose to observe pressures from a gas storage well to monitor the field operations over an extended period of time, and those wells should not be considered an idle well.

Response: NOT ACCEPTED. The definitions of “idle well” and “active observation well” are both found in PRC section 3008, and those statutory definitions do not include an exclusion for wells that have been gas storage wells.

0015-18, 0025-3

§1726.1(a)(5): The definition of “reservoir” should include depth and lateral intervals, and recognize that natural gas can be stored in aquifers or salt domes. Thus, the definition of reservoir should include reference to the geologic formation. The differences between “reservoir” and project, and “area of influence” should also be defined, graphically and numerically.

Response: ACCEPTED IN PART. The definition has been clarified to include the “portion of the geologic stratum” that is being used to store natural gas. This includes depth and lateral intervals and clearly defines the difference between reservoir (geologic) and project (human operation).

NOT ACCEPTED. “Area of influence” is not used in the proposed regulations, so it does not need to be defined.

0024-16

§1726.1(a)(5): The term “observation well” should be added to the list of definitions.

Response: NOT ACCEPTED. The existing definition for observation well appears in PRC section 3008, subdivision (c). An additional definition within the proposed regulations is not needed.

0003-1

§1726.1(a)(6): The language should be amended to ensure greater clarity on the definition used for “underground gas storage project” as waste gas disposal should not be considered storage. By limiting the definition to a project “...for the purpose of temporary storage prior to commercial sale.”

***Response:** NOT ACCEPTED. Gas storage is not always temporary and not always for commercial sale.*

0008-1

§1726.1(a)(6): Where is the jurisdictional end-point for the high-pressure gas injection and production piping within the gas storage field?

***Response:** The Division’s regulatory efforts are focused on the wellbore and its associated infrastructure. Through agreements with other jurisdictional entities, the Division works to ensure that potential hazards are mitigated without conflicting or duplicative legal requirements.*

0015-19, 0052-7

§1726.1(a)(6): The definition of “underground gas storage project” should include storage, fluids, lateral and underlying formations, in any zone(s), and ensure that any processing, pumping, or compressor facilities are excluded from the definition of a project.

***Response:** ACCEPTED IN PART. The definition for caprock has been modified to a definition for confining strata, which includes all boundaries (lateral, underlying, and otherwise). This term has been incorporated into the definition of UGS project, effectuating the recommended change.*

NOT ACCEPTED. The addition of “storage” is duplicative as the storage purpose is already included. Adding “fluids” would likely indicate that waste water disposal wells are included in the definition, but the proposed regulations are not intended to apply to disposal wells.

1726.2 **APPROVAL OF UNDERGROUND GAS STORAGE (UGS)**
PROJECTS

0015-9

§1726.2: Before operations of projects, wells, and reservoirs, the operator shall document all releases, leaks, spills, blowouts, ventings, or flarings and shall undertake, complete, and submit to the Division thorough and independently verified “root cause analyses” for such events, a remediation/upgrade program for all project wells, and such remediation/upgrading within one year of approval of the project.

Response: *ACCEPTED IN PART. The proposed regulations require the operators to do an assessment of their wells as part of the RMP. Where wells are not in compliance with the well construction standards, they must be brought into compliance on an approved schedule.*

NOT ACCEPTED. The sheer number of wells that may need to be upgraded makes a one-year deadline infeasible. Additional risk mitigation measures will be required on these wells until fully compliant. A root-cause analysis would generally not be needed for ventings or flarings, as they are routine procedures regulated by air quality management districts. Other releases, leaks, spills, and blowouts are already documented by the Division at the time of the incident and a root-cause analysis is required if needed.

0024-19

§1726.2: The Division should establish a process and response timeframe for reviewing and approving an operator’s new UGS project.

Response: *NOT ACCEPTED. Different projects have differing levels of complexity and risk. While some operators do a very thorough job with their submissions, others may require multiple communications and exchanges regarding additional information and data needed. The Division cannot rush an approval in order to meet a regulatory deadline but must prioritize ensuring that sufficient oversight of the project has been provided.*

0031-2

§1726.2: There is insufficient detail for terms of project approvals, relative to rights to appeal and for due process.

Response: *NOT ACCEPTED. If an operator’s project approval is affected by an order of the supervisor, then the operator’s rights to appeal are found in PRC sections 3350-*

3359, which apply to all orders of the supervisor to operators of a well or production facility.

0008-2, 0030-7, 0052-5

§1726.2(a): The requirement that operators obtain a PAL should be accompanied by a process for public notice and opportunity for comment before any PAL is issued. Commenters also note that because DOGGR's decision to issue or modify a PAL is a discretionary action of the agency, any such approval would be subject to environmental review requirements under CEQA.

Response: *NOT ACCEPTED. Permitting for a new intrastate UGS project is initially under the control of the CPUC and permitting for a new interstate UGS project is initially under the control of the Federal Energy Regulatory Commission (FERC). Both the CPUC and FERC permitting processes include comprehensive environmental review and extensive opportunity for comment. Once permitted by the CPUC or FERC, the operator would apply to the Division for project approval..*

0019-1

§1726.2(a): It is unclear if there are any prerequisites for obtaining a PAL. For example, would the RMP have to be submitted and reviewed prior to issuing the PAL? It is recommended that the RMP be submitted and reviewed prior to issuing the PAL.

Response: *In practice, the Division would require all required project data and a completed RMP prior to finalizing a PAL for a new UGS project. The process of generating a PAL for a new UGS project will begin while the project is still undergoing its initial review and authorization with the CPUC and local land use agency. The CEQA report will identify potential hazards as well as mitigation requirements, and the Division will participate in the evaluation of the geology of the site and its appropriateness for use as a UGS project. Using the CEQA results and their own analysis, the operator will develop the RMP and submit it along with required data to the Division. The PAL will be issued once the location has been approved by all participating agencies and the RMP has been submitted and approved with provisions for the integrity testing and monitoring as required by the regulations. Existing projects will have six months from the effective date of these regulations to submit their RMP.*

0019-2

§1726.2(a): The requirements for PALs related to current UGS operators is unclear. The Division should require all existing gas storage projects to reapply for PALs and be

brought into compliance with all aspects of the new regulations, once finalized, and specify a timeframe for doing so.

Response: *NOT ACCEPTED. The proposed regulations provide implementation timeframes for the new requirements, including six months for the RMP and ERP, and 90 days for new project data requirements. Under the RMP, each well must be evaluated and a percentage of wells not in compliance must be brought into compliance each year until full compliance is achieved.*

0024-17

§1726.2(a) and (d): A PAL must only be obtained for any new project. PALs for existing storage projects remain in effect unless there are data updates.

Response: *NOT ACCEPTED. PAL requirements apply to all projects. Where a project is operating under an existing letter, the project must still be updated to meet the requirements of the proposed regulations, and project data must be updated and maintained.*

0026-11

§1726.2(a): Edits should be made to ensure that operators and the Division have a consistent baseline understanding of the operational parameters, and that the parameters are detailed in the PAL by including “Any changes...as set forth in the Project Approval Letter”.

Response: *ACCEPTED. Language has been added as suggested.*

0017-8, 0019-3, 0025-4

§1726.2(b): Commenters support the Division’s proposal to set a fixed frequency for performing reviews of gas storage projects. This is crucial to ensure that projects are adhering to the terms and conditions of the PAL and to determine whether operating conditions warrant updates to those terms and conditions, to ensure that public health and the environment are being protected. Such reviews should be conducted, at a minimum, on an annual basis.

Response: *NOT ACCEPTED. Because any changes already require notice to the Division, project conditions do not otherwise change frequently enough to necessitate annual review in all cases. Taking into consideration the Division and operator resources required to perform a review, three years is sufficient to ensure that conditions of the project have not changed so as to violate the PAL or create a risk of*

harm to life, health, property, natural resources, or the environment. The Division can target those projects that are more likely to have issues for earlier or more frequent review as appropriate.

0026-12

§1726.2(b): Edits should be made to clarify the process for suspending, modifying or rescinding a PAL. A Supervisor Order that identifies the specific matters of non-compliance is the appropriate procedural mechanism and this clarification is needed because of the potentially serious consequences of modifying or ceasing operations at a gas storage project, which could cause, among other things, impacts to gas supplies or electric grid reliability. In addition, this approach is consistent with PRC sections 3202(c), 3224, and 3226, among other sections, where an order by the Supervisor establishes remedial actions that must be taken by the regulated party. The Supervisor should be permitted to issue this order only if evidence demonstrates that specific requirements of the regulations are not being complied with.

0022-8, 0026-13, 0026-14

§1726.2(c): Some matters of non-compliance (with a current PAL) can be addressed without ceasing operations. An order requiring cessation of operations should be limited to circumstances where the Supervisor determines doing so is necessary to prevent an imminent threat to life, health, property or natural resources. Specifically concerning is the provision which permits shutdowns where there are inconsistencies with the terms and conditions of a current PAL, which could potentially result in shutdowns even for deviations for ministerial or administrative requirements (such as a late-filed report). Clarification is recommended because of the potentially serious consequences of modifying or ceasing operations at a gas storage project, which could cause, among other things, impacts to gas supplies or electrical grid reliability. Where there is no imminent threat, the owner or operator shall be required to submit a plan to address the non-compliance but cessation of operations should not be required.

Response to 0022-8, 0026-12, 0026-13, 0026-14: NOT ACCEPTED. Where life, health, property, natural resources, or the environment may be threatened, the Division must have the ability to modify, suspend, or rescind approval to mitigate the threat. If an operator's project approval is affected by an order of the supervisor, then the operator's rights to appeal are found in PRC sections 3350 to 3359, which apply to all orders of the supervisor to operators of a well or production facility.

0030-8

§1726.2(b) and (c): There should be a penalty provision for operators who do not first obtain a PAL, or who operate outside the conditions of an existing PAL. Such enforcement authority must be more clearly delineated. For instance, under subdivision (b), the Division will “review UGS projects to verify adherence to the terms and conditions of the PAL” and “periodically” review the terms and conditions of the PAL. The Division must clarify how often each of these reviews will occur, and how many violations of the PAL will result in DOGGR suspending or rescinding a PAL. Similarly, under subdivision (c), the Division must clarify what conditions will trigger the written notice from the Division requiring operations to cease, or whether only certain operations will trigger such a letter. Is it any operation that is inconsistent with a PAL, or only certain operations? Is DOGGR’s duty to send notice mandatory under certain conditions, or is it always discretionary?

Response: *NOT ACCEPTED. The Division’s authority to issue civil penalties for violations of statute or regulation is found in PRC sections 3236.5, which includes limitations and considerations for determining the amount of a civil penalty.*

0015-54

§1726.2(c): The situations where operators must cease operations under this subsection must be expanded to include those times when the Division determines that the operations and design of an UGS project are inconsistent with current PALs. If such a determination is made, facilities and/or operations should be required to cease immediately.

Response: *NOT ACCEPTED. Any feature of operations which is inconsistent with the PAL, including the requirement to be in compliance with existing regulations, is considered a violation. The Division has various statutory enforcement authorities, including the ability to issue an order to suspend operations.*

1726.3 RISK MANAGEMENT PLANS (RMPs)

0010-5

§1726.3: Proper evaluation of RMPs requires analysis by trained and experienced professionals in risk management. DOGGR should build this capacity in its staff. One way to enhance this process is to adopt a standard template like ALARP (as low as reasonably practicable) to help evaluate whether plan elements sufficiently mitigate risk to DOGGR’s standards. Commenter recommends DOGGR consult a whitepaper prepared by sister agency the CPUC, which was considering adopting ALARP for its

own purposes. While DOGGR can make good use of ALARP analytical approaches to inform its evaluation of risk management efforts, commenter does not see a need to incorporate the concept into the rule language in order to make sure there is a standard that spells out how much risk reduction is enough (a standard that is missing in rules adopted by PHMSA). This is so because California's proposed rule already provides that an RMP will be approved only if the agency finds to its satisfaction that stored gas will be confined to the approved zone(s) of injection and that the UGS project will not cause damage to life, health, property, or natural resources.

Response: *The Division is working with various experts in the area of risk management planning to identify ways to effectively evaluate RMPs. One recommendation includes peer review by a second entity. The Division is exploring its partner relationships to determine what agency might be willing/able to participate in this peer review. Simultaneously, Division UGS program staff are participating in extensive training on risk management assessments and methods, including documents prepared by other agencies (such as CalTrans' Project Risk Management Handbook) and programs developed by staff at the University of Texas at Austin, Colorado School of Mines and Penn State. The Division has reviewed the CPUC whitepaper and are continuing to develop Division staff skill sets in this area.*

0025-5

§1726.3: Regulations related to RMPs should be standardized and require operators to consider the threats and hazards associated with each aspect of the UGS project including broadly, well design and construction, well integrity, well operation and maintenance, monitoring, geologic uncertainty, natural threats and hazards, ground water quality, emergency response, well intervention, material balance, third-party threats and hazards, and reservoir threats and hazards. More specifically, the need to address threats and hazards associated with gas containment failure due to inadequately completed wells, sealed plugged well(s), failure of cement squeeze job perforations or stage tool, pressure rating of components, the presence of any potentially toxic substances in the injection stream or the formation, formation pressure, proposed injection pressure, cement bond failure, material defect, valve failure, gasket failure, thread leaks, chemical or mechanical damage, tubular integrity, corrosion potential, inadequate procedures, failure to follow procedures, inadequate training, inexperienced personnel and/or supervision, uncertainty regarding the extent of the geologic boundary, expansion, contraction and migration of storage gas, failure of the caprock, seismicity, faults, subsidence, inundation by tsunamis, seal level rise, floods, containment failure due to loss of control during drilling, reconditioning, stimulation, logging, and working on downhole safety valves, intentional or unintentional damage to

wells, the storage reservoir, caprock and/or surface equipment from third-party activities including drilling, completion, workover, production, injection, and disposal, and contamination of the reservoir by foreign fluids. Once all the threats and hazards have been evaluated, the plan should require the development of preventative and mitigating measures to address those threats and hazards.

Response: *ACCEPTED IN PART. The inclusion of human failure and human error as part of the risk assessment process is an important addition. Language has been added to ensure that personnel-related risk is assessed as part of the RMP, and the requirement to consider geologic hazards has been expanded to include natural hazards.*

NOT ACCEPTED. The plan already requires the development of mitigating measures once hazards have been evaluated; it is not the goal of the proposed regulations to list every potential risk that may affect each well. Operators must use their judgement as oil field managers to determine what risks must appropriately be considered given the challenges of each specific wellsite and the needs of their operation. The Division will work with operators to ensure that a comprehensive RMP is in place and is regularly updated, but the level of detail proposed by commenter is far too prescriptive or otherwise duplicative.

0030-16, 0035-4

§1726.3: RMPs should include requirements to conduct root-cause analyses after significant failures or releases, accidents and near-accidents. The results of the analyses should be publicly available online. Identification and prioritization of risks, threats, hazards, and mitigation should include the results of root-cause analyses. Without a root-cause analysis you can't sign off on safety.

Response: *NOT ACCEPTED. The RMP is focused on the prevention and mitigation of harm including initial emergency response to serious incidents. Post-incident response is determined on a case-by-case basis depending on the type and seriousness of the incident and the resulting or potential harm. Where a cause is known, the performance of a root-cause analysis would not be an effective or efficient response.*

0030-19

§1726.3: The RMP should include a requirement for a publicly accessible database of reported leaks and threatened leaks; emissions and air monitoring data; near-miss performance metrics; maintenance and safety requests made; corrective actions taken or not taken; outcomes and results; the management individual accountable; and results of unannounced random onsite inspections.

Response: NOT ACCEPTED. Where such information and data has been submitted to the Division, the information will generally be available to the public through the Division website. It is not necessary to describe those practices in regulation.

0030-70

§1726.3: RMPs must be required for each field.

Response: ACCEPTED. Proposed section 1726.3(a) requires an RMP “for each underground gas storage project,” and comments suggesting that multi-field plans should be permitted have been rejected.

0035-5

§1726.3: Commenter indicates the need to consider the danger to homes that are downhill from gas storage facilities. Poisonous gases, the most dangerous substances, are heavier than air and move downhill rapidly. Substances like hydrogen sulfite, mercaptans, and radon are all heavy substances that are likely to affect downhill areas.

Response: ACCEPTED. The specific requirements for the RMP have been expanded to require a quantitative risk assessment, which includes the need to identify natural features that will affect the extent of threats and hazards, and a quantification of their relative roles. Where a geologic feature, such as a hill, will affect the way that gases flow out from a UGS facility, it must be identified and quantified as part of the RMP.

0039-3

§1726.3: During the Northridge Earthquake, all the lights were out, and commenter walked out of their house and looked up in the hills to see real fires from the gas wells. Commenter is concerned about seismic safety at nearby UGS projects. There was enough illumination from those fires that commenter didn’t need lights.

Response: Fire and seismic risk must be considered as part of the RMP and ERP.

0010-2

§1726.3(a): Changes should be made to ensure that a company’s RMP is properly adhered to at all levels of the company, from the CEO to the field staff. RMPs are only effective when companies have done the following: developed a policy that is supported by executive management and understood by all, established lines of management responsibility and accountability, integrated the RMP into organizational processes, provided for all required resources to support the RMP, initiated the RMP, provided for a

continual improvement framework, established open and transparent lines of communication within the entire organization, applied RMP in all decision making and fully integrated the RMP into organizational governance. To that end, proposed additions include (but are not limited to) provisions on resource allocation, integration into the company's processes, internal and external communication protocols, mechanisms for continuous improvement, and a requirement to show that the company is in compliance with the plan at all levels. These additions were drawn from industry standard practices on risk management.

Response to 0010-2, 0030-18: *NOT ACCEPTED. These comments point to a level of involvement in the internal management of companies that the Division does not intend to pursue. The goal of the proposed regulations is to provide clear performance standards and minimum criteria for an effective RMP, and leave operators with maximum flexibility to determine the best approach to compliance.*

0010-3, 0024-3, 0026-7

§1726.3(a): The RMP cannot demonstrate that all risk will be eliminated and that risk-inducing events will never happen. The language should be modified such that the practices within the management plan effectively address and mitigate the risks associated with operating a natural gas storage facility. There is inherent risk that is impossible to completely eliminate and as such, risk management practices need to *manage*, not eliminate, the risks through mitigation practices.

Response: *ACCEPTED IN PART. Instead of "prevention protocols," this section of the proposed regulations now refers to "prevention and mitigation protocols" in acknowledgement that risk of harm cannot always be prevented, but can be mitigated to the extent technologically feasible.*

0015-20, 0017-2, 0017-3, 0019-4, 0019-5, 0024-22, 0030-9

§1726.3(a): There should be a requirement for submission and approval of RMPs within a specific timeframe. Recommended alternatives include submission within 30 days, 120 days, or 180 days after the regulations become effective. There should also be penalties for failure to submit a timely plan, and the process by which the Division will review and approve the RMP. The approval period should not exceed 90 days after receipt and rejection of plans should be accompanied by a written explanation of noted deficiencies.

Response: *ACCEPTED IN PART. Language has been added to provide that the RMP is due within 6 months of the effective date of the proposed regulations. The*

development of an effective RMP takes significant time and will continue as conditions and expertise evolve, suggesting that a shorter timeframe is insufficient. For new projects, the PAL will not be issued until the RMP has been submitted and approved. NOT ACCEPTED. Penalties for issues of non-compliance are provided for by statute and do not need to be included in regulation. The Division will review and respond to the plan as quickly as is reasonably possible, but cannot commit to a specific deadline for approval of a plan that has so many complex and detailed parts. Where the Division finds the plan insufficient, a written explanation of deficiencies and recommended improvements will be issued and the Division will work with the operator to get to compliance.

0017-7, 0030-53

§1726.3(a): There should be regular review of the RMP. Alternatives proposed include annual review, review every two years, or review every three years.

Response: *ACCEPTED. The RMP is a comprehensive plan that is anticipated to take 3-6 months to develop, even for operators who are already using risk assessment and hazard analysis in their operations. Given that regular review will be a time-consuming process if performed correctly, annual review is not cost-effective. Operators are required to update their plans for changing conditions as needed and to transmit information regarding those updates to the Division. The review schedule has been set at no less than every 3 years to accommodate these realities.*

0019-8, 0030-17

§1726.3(a): The RMP should employ hazard reduction methodologies that are industry standards, or recognized and independently vetted methodologies that are generally accepted as good engineering practices which shall be approved or accepted by the Division. The plan, fundamentally, is not a standalone document. The submitted RMP and the actual implementation of the hazard assessment and prevention protocols must work in concert and be evaluated comprehensively. Therefore, the RMP cannot demonstrate that the UGS project “will not cause damage to life, health, property, and natural resources.” The goal of any RMP is to prevent damage, there is no RMP that can demonstrate they will not.

Response: *NOT ACCEPTED. Protocols and methods included in the RMP will be required to be valid and reliable including evidence-based, but will not be limited to only those methods that have been independently vetted and approved. A goal for the regulations is to encourage operators to creatively use new technologies and methodologies that would achieve the regulatory goals more effectively and efficiently.*

The Division will work with operators to ensure that innovation does not create excessive risk, but innovation in the development of better safety technologies is encouraged.

0024-20, 0026-6

§1726.3(a): In order to, among other things, maintain consistency and a central repository of RMP information applicable to storage fields, the regulations should be revised to allow entities with multiple storage fields to maintain a single RMP that covers it facilities. This proposed single RMP would be required to contain elements and subsections to address where unique attributes or conditions at an individual field may require site-specific modifications to the plan. A single RMP will provide centralization and consistency with a risk-based methodology, which involves data collection, documentation and review, hazard and threat identification, risk assessment, preventative and mitigative measures, and periodic review and reassessment.

Response: *NOT ACCEPTED. PRC section 3181, subdivision (a)(2), requires operators to have RMPs addressing hazards of every individual well, with site specific information and well-by-well hazard analysis, making a multi-field plan impossible to manage and too large to effectively implement. Different fields will have different levels of complexity and a combined plan will extend the timeframe for review and approval, delaying plan implementation because of the complexity of evaluating a multi-field plan. In addition, when implementing a plan, site personnel should be focused on those risk assessments and mitigation measures appropriate to their site, rather than trying to extract their site-specific requirements from a larger and more complex document. To ensure that RMPs are effectively developed and implemented based on site-specific risk assessments completed on a well-by-well basis, a project specific plan is required.*

0024-21

§1726.3(a): Submission of a plan containing the required elements to the Division should be sufficient and approval by the Division should be removed from the regulatory language.

Response: *NOT ACCEPTED. Approval of the RMP by the Division is required by statute under PRC section 3181, subdivision (a).*

0024-25

§1726.3(a): Commenter interprets the Division's request for authority to approve the RMP to suggest that the approved plan contains all the necessary elements the Division requires. Along those lines, the Division should remove the language in this section

giving the district discretion to require additional data beyond that required in the RMP as the requirements should fully include all the criteria required by the Division.

Response: *NOT ACCEPTED. At the time an RMP is approved, the Division will ensure the plan covers existing conditions, uses best practices, and has considered newly-available technologies. Over time however, additional data may be needed as site conditions change or as additional information becomes available. For example, encroaching land uses around the project may change the risk of harm to surrounding communities or technologies may come down in price such that mitigation measures and more accurate methods of data collection become cost-effective. Additional knowledge and analysis may also take place, as storage operators, service contractors, scientists, and regulatory agencies learn from and adapt to hazards and conditions. These changes are reflected in the ongoing evolution of industry standards and best practices, and are based in a recognition that no physical or environmental risk analysis can be fixed in time. The operator is required to update the plan and notify the Division when it becomes aware of these types of changes, and the Division will do the same.*

0024-26

§1726.3(a): The clause giving the Division discretion to require modification of prevention protocols and risk assessments should be removed. Plans to execute mitigation and risk management programs are incorporated into our rate case testimony approval for funding. As such, alterations to these plans, if required by the Division, could impose significant costs beyond authorized expenditures.

Response: *NOT ACCEPTED. The operator is required to update the plan and notify the Division when it becomes aware of any changes which would affect the efficacy of its risk assessments and chosen prevention protocols. The Division will do the same when additional information is available that suggests there is a potential for harm to life, health, property, natural resources, or the environment. The existence of a rate case is not sufficient to justify ignoring changing site conditions which require additional risk consideration. The operator must be prepared to alter its plan as needed to adjust to these conditions and the Division will require it as appropriate.*

0024-27

§1726.3(a): The Division has written in a review period for projects that does not exceed 3 years in proposed section 1726.2(b), which commenters interpret would include review of project performance as well as existing procedures. For this reason, the review cycle should be noted in that section only and removed from the language of this

subdivision. Language specifying that a schedule for operator review and submission of plan updates should be included in the plan.

Response: *NOT ACCEPTED. The project review contemplated by proposed section 1726.2(b) would generally include the RMP and all other PAL conditions and requirements. However, the periodic review is also included in the proposed RMP provisions to ensure that all operators are aware that the RMP will be included in the project review and to allow for review of the RMP as a separate process from the review of project conditions under the PAL.*

0030-10

§1726.3(a): This section states that RMPs must specify a schedule for submitting updates to the Division. The RMP should go further and create a comprehensive risk management approach that requires operators to apply a prevention-oriented “inherently safer systems” process that is flexible and iterative. This process should require the operator to conduct a review and reassessment of the risk assessment and prevention protocols; the Division should specify minimum requirements for such periodic review and reassessments. In addition, the Division should require that operators continually and iteratively assess alternative technologies and processes in order to incorporate the least hazardous approaches and technologies. Commenter recommends that DOGGR review examples of this comprehensive approach including the California Interagency Working Group on Refinery Safety recommendations, approaches recommended by the Chemical Safety Board, and RMP protocols for other hazardous industries, to ensure that the risks from gas storage operations are as low as reasonably practicable. DOGGR should also review the proposed EPA rule for improving the regulations for RMPs under the Clean Air Act, which includes a requirement for process hazard analyses; enhancements to emergency preparedness requirements; increased public accountability and availability of information such as chemical hazard information and other requirements.

Response: *NOT ACCEPTED. The proposed regulations provide for regular updates to the Division as needed, so a specific schedule would vitiate the responsive nature of these updates. The RMP for each UGS facility will be reviewed no less than once every three years and will be updated as needed as part of the review process. The RMP is a comprehensive approach, but the level of detail recommended by commenter is too prescriptive and creates requirements that are difficult to enforce. The Division has reviewed the documents recommended and will incorporate lessons learned into its evaluation of RMPs as they are submitted and updated.*

0019-9, 0026-15

§1726.3(b): The requirement to include information on “third-party guidance” relied upon in the development of the RMP should be changed to industry standards or industry recommended practices. This would ensure the appropriate industry standard or that the best practice is utilized.

Response: *NOT ACCEPTED. It is the goal of the Division to keep the world of potential guidance and reference for the RMP as broad as possible. There may be many good strategies and tools for risk management that have not been specifically included in known industry standards, including tools from other industries and unexpected sources. The Division will evaluate all RMPs carefully to ensure that scientifically appropriate and effective methods will be used; there is no need to limit the potential sources for guidance in plan development.*

0021-3

§1726.3(b): New rule making should require that RMPs be professional quality documents and DOGGR should not accept poorly supported documents such as “Supplement to SoCalGas’ Storage Risk Management Plan #2, (10/11/2016)”. Our review of that plan is available at:
http://geologicmapsfoundation.org/resources/GMF_Comment_to_Risk_Mgmt_Plan_2_06Feb2017_Final.pdf

Response: *The Division has created and is training a dedicated program team for UGS inspection and oversight. Program staff are working with scientists and experts in the field of risk management planning to identify standards for RMP evaluation that will be consistent with various legislative and best practice requirements to ensure that failure scenarios are considered and appropriately mitigated.*

0024-28

§1726.3(b): The references to third-party guidance should be removed, as commenter relies on many sources of information from various parties and this would be unduly burdensome to include.

Response: *NOT ACCEPTED. If the operator is unable to provide information about a source on which it has relied for a part of the RMP, it should not rely on that source. The Division cannot evaluate the risk assessments and proposed mitigation protocols without information about the evidence and analysis that supports the scientific appropriateness and efficacy of protocols included in the RMP.*

0026-23

§1726.3(b)(1): Commenter suggests deleting this proposed section related to “collisions involving well heads” and replacing with “accidental impacts by moving objects (e.g. farm equipment, cars, trucks, etc.)” to be consistent with API RP 1171.

Response: *NOT ACCEPTED. Accidental impacts are only one category of risk and would be considered part of the larger category of “collisions.” “Collisions” is a broader category that would also include planned or intentional impacts to the wellhead.*

0024-29, 0026-16

§1726.3(b)(3), (4) and (5): Commenters fully support robust risk identification and mitigation selection processes and suggest combining documentation of the process into one line item.

Response: *NOT ACCEPTED. Combining subdivisions (b)(3)–(5) would not improve the clarity of the proposed regulations.*

0024-30

§1726.3(b)(3): Language related to cost should be removed from the regulations as funding falls under the purview of the CPUC.

Response: *NOT ACCEPTED. Because the Division will use this information in determining if the protocols will be sufficient to mitigate risk under the RMP, efficacy and cost-effectiveness information must be included to inform that analysis.*

0026-17

§1726.3(b)(6) and (7): Commenter suggests elimination of these sections and replacement with a requirement to “validate the risk assessment process through feedback and regular periodic reviews to update information.” This suggested change would be in alignment with API RP 1171.

Response: *NOT ACCEPTED. These sections include a timeframe for when data feedback and validation must take place, and require a review no less than every three years. This timeframe has been eliminated by commenter to align with API RP 1171. However, as API RP 1171 is a guideline document not intended to create enforceable regulatory requirements, it does not include timeframes for update and review. Because members of the public and environmental groups would like to see mandatory annual reassessment, the Division must balance the desire for specific enforceable requirements with the need for operators to maintain flexibility. The timeframes specified*

in the proposed regulations are a balance between these competing needs, as is appropriate for a regulatory program.

0010-43

§1726.3(c): Risk assessment, prevention, and mitigation protocols for the protection of groundwater should be included as a required element of RMPs as a standalone subsection.

Response: *NOT ACCEPTED. Protection of groundwater is inherent to the intrinsic goals of the proposed regulations of ensuring well integrity and the confinement of fluid to the approved zone(s) of injection.*

0020-6, 0020-7, 0024-1

§1726.3(c): Commenters support the use of a risk-based approach for assessing existing wells and designing new wells, determining the appropriateness of safety valves, monitoring, and evaluating corrosion, and verifying integrity of the wells and reservoirs. In order to align with API RP 1171, commenters recommend removing prescribed prevention protocols from the risk management section and streamlining the section to focus on the required risk assessments. The appropriate prevention protocols will be determined by the outcomes of the risk assessments. By applying risk management practices, determinations can be made in each operator's RMP on the appropriate well design and construction to protect the integrity of the well.

Response: *NOT ACCEPTED. The proposed regulations are based on API RP 1171 and the risk-based assessment approach. However, this section is not just focused on risk assessments but on the RMP as a whole. The RMP must include provisions for the risk assessments and for the actions to be taken as a result of risk assessment, including prevention and mitigation protocols, testing frequencies and methods, the ERP, and any other protocols that may be necessary to ensure the protection of life, health, property, natural resources, and the environment.*

0030-14

§1726.3(c): Throughout this subsection, there are several points at which either the operator must propose a schedule for, or the regulations require, "ongoing" verification, monitoring, and/or demonstration of well integrity or evaluation of pressures. The regulation should clarify "ongoing" to mean continuous monitoring and/or provide the minimum frequency verification should occur.

Response: NOT ACCEPTED. The requirements for demonstration of well integrity and pressure evaluation of this proposed section are part of the RMP, which requires the operator to use risk assessments based on specific site hazards and well characteristics to determine the appropriate frequency of monitoring and verification. Where “ongoing” is used in reference to monitoring of casing pressures and integrity demonstration, the requirement is not for continuous monitoring, but for regular monitoring based on risk assessment. Thus, the frequency will be determined by risk analysis, not regulatory prescription.

0020-8, 0024-31

§1726.3(c)(1): Commenters recommend the removal of the reference to “life expectancy of individual mechanical well barrier elements.” Integrity of steel piping and components throughout the life of a well is a function of its environment, including the presence or absence of cement, the presence or absence of corrosive/erosive fluids, operations and maintenance. Condition-based assessments should be applied throughout the life of a well to confirm integrity of piping and components, instead of relying merely on age or an initial “life expectancy.”

Response: NOT ACCEPTED. The inclusion of information related to life expectancy does not suggest it should be the only factor considered. Reliance on any single factor would be unreliable. Condition-based assessments should be applied throughout the life of the well. All information that is available and which would contribute to a more accurate assessment of the likelihood of integrity loss should be considered, including life expectancy.

0030-11

§1726.3(c)(1): Under this section, wells not in conformance with section 1726.5 well construction standards need only include a “work plan for either bringing the nonconforming wells into conformance or plugging and abandoning the wells.” Wells that are not in conformance pose a significant health and safety risk. All non-conforming wells should immediately be taken out of use and returned to use only once the operator has shown that conformance has been achieved. Leaving them operating as-is simply cannot be justified given the hazards they pose.

Response: NOT ACCEPTED. The proposed regulations provide a phased timeframe for operators to bring all wells into compliance. Where a specific well may be a risk to life, health, property, natural resources, or the environment, the Division has the authority to require mitigation measures, shut-in, or plugging as needed. The RMP will be required to identify non-compliant wells and ensure that appropriate mitigation

measures are used to address risks associated with these wells. All project wells must be evaluated for hazards with quantitative risk assessment and identified mitigation measures as part of the RMP, regardless of their current condition or level of compliance with these standards.

0030-13

§1726.3(c)(2): The criteria listed in this section may be better suited for determining whether a well should exist at all within a certain proximity to populations, or whether a buffer zone in which no gas wells may operate is more appropriate to protect health and safety.

Response: NOT ACCEPTED. The criteria in this section is used for determining whether or not the use of a subsurface safety valve is appropriate. The proposed regulations require a RMP for each UGS facility that includes evaluation of threats and hazards associated with operation of the underground gas storage project and identification prevention and mitigation protocols that effectively address those threats and hazards. Consideration of proximity to people is inherent to the RMP process.

0019-10

§1726.3(c)(2)(F): “Proximity to environmentally or culturally sensitive area” should be changed to “the well’s distance to environmentally or culturally sensitive areas.” This is similar to subdivision (c)(2)(A), the wells distance from dwellings. Distance is an objective metric, whereas proximity is not a defined metric and may easily or intentionally be ignored.

Response: NOT ACCEPTED. Proximity as used in this proposed section is intentionally flexible. As part of the risk assessment process, operators should consider not just their distance from a sensitive area, but also the relationship between operational activities and impacts on those areas. Distance is limited to a physical measurement, while proximity is an expansive term intentionally used to include topography and other characteristics of a site that would affect impacts on surrounding sensitive areas regardless of, and independent from, any specific distance measured.

0024-32

§1726.3(c)(2)(J): Commenter recommends eliminating this section in its entirety and suggest that only current conditions need to be considered by the operator due to the lack of predictability associated with the completion of any future or planned development. Consideration of nearby population centers is sufficiently captured in subdivision (c)(2)(A). When considering approval for future land use, it is up to the

approving entity (i.e., city, county, state, Bureau of Land Management) to consider approval of projects based on proximity to land uses, including underground storage facilities.

Response: *NOT ACCEPTED. The RMP must account, not just for risks to land uses that exist at the time a project is approved, but also land uses that come into being after the project begins operations. In addition, it is not just risk from the project to the land use that must be considered, but also risk to project wells from the encroaching land uses. Operators must monitor for upcoming development as well as existing development or they may end up with a neighbor that puts their project at risk. Operators should work with local land use agencies in the jurisdictions surrounding their project to maintain the integrity of the project and ensure the safety of future development by monitoring local agency activity and responding to development proposals that would affect or be affected by the project. This is hazard mitigation work that is an integral part of an effective RMP.*

0021-4

§1726.3(c)(2)(L): RMPs need to specifically recognize the hazard and risk to gas well integrity posed by active and potentially active faults that intersect storage wells. Storage fields that have many wells crossing such faults to reach the storage reservoir are a significant risk to public safety, the environment, and energy supply if the fault were to move and compromise the integrity of multiple wells. New rules for RMPs should specify, in detail, and require a standard approach to fault displacement hazard evaluations that is at least equivalent in scope to evaluations done for major surface projects such as dams, tunnels, large building projects, etc. that are located adjacent or above active or potentially active faults. New rules should require RMPs to disclose if any portion of a fault that crosses a gas storage well is a State of California recognized surface displacement hazard identified to be within an Alquist-Priolo Act (AP) zone. For instance, the Santa Susana fault that crosses all of the wells at the Aliso Canyon gas storage field is within an AP zone because the eastern segment of the fault had surface displacement during the 1971 Sylmar earthquake (MW=6.4-6.7). It is recommended that DOGGR consult with the State of California Geological Survey that has extensive experience with active faults and these types of hazards, to develop a standard approach.

Response: *ACCEPTED IN PART. Seismicity and its associated hazards are a required consideration of the risk assessment and mitigation process included in the RMP. NOT ACCEPTED. The RMP will identify the appropriate data and mitigation protocols needed to account for seismic hazards and any associated risks. The specific*

requirements recommended by commenter are too prescriptive. Where the Division is unsatisfied with the quality of information or analysis provided, it can require additional information as needed based on site-specific characteristics and hazard analysis.

0019-11, 0021-2

§1726.3(c)(2)(L) and (c)(9): The regulations should require that any geologic hazard or seismic analysis be conducted by an engineer or professional geologist, who is qualified to make such evaluations. This may already be required by State of CA regulations: see http://www.bpelsg.ca.gov/about_us/. For technical and scientific accountability, the third-party's reports and communications need to show the geologist's California professional certificate number and license seal stamp.

Response: *NOT ACCEPTED. Operators should not be prevented from using appropriate subject matter experts where their input may make risk assessment and mitigation protocols more effective. The Division will not accept any scientific reports from someone who is not qualified under law and by training to issue them, but it does not want to limit the scope of experts who may be able to contribute to the efficacy of an RMP by specifying required professional credentials.*

0022-4

§1726.3(c)(3): The regulations should explicitly provide that all compliance elements of the RMP, including type and frequency of testing protocols applicable to each well at an underground storage project, will be determined using a risk-based approach.

Response: *NOT ACCEPTED. The risk-based approach is generally used but is not exclusive, as some elements of the RMP intersect with minimum standards found elsewhere in the regulations. PRC section 3180 requires the Division to set a schedule for ongoing testing of gas storage wells, and proposed section 1726.6 establishes requirements for the type of testing to be conducted as well as key parameters for the required testing.*

0015-21, 0052-8

§1726.3(c)(4)(B): In the requirements for the RMP, the required consideration of corrosion potential should be expanded to include liquids, fluids, gases and other phases/media including the impact of temperatures, and compositions.

Response: *ACCEPTED. Temperatures and compositions have been added to the factors for the consideration of corrosion potential on the wellbore.*

NOT ACCEPTED. Liquids, gases, and other phases are already included in “fluids and solids.”

0015-23

§1726.3(c)(5): Digital models and graphical process flow diagrams should be required in the RMP, including a good computer model for the pressures, temperatures, and flows going in and out, and where they go beyond the boundaries of the project. Computer modeling should also include wells collision maps showing their paths, functions and depths so it can be understood how physical arrangements are developed in addition to the dynamic arrangements. As we assume the gas companies have some computerized means of operating their facilities, these models should be available to DOGGR and the public.

***Response:** NOT ACCEPTED. Although some operators may already have these systems, smaller operators often use more human resources than technological ones. Computerized operations systems may also not have these types of modeling capacities as they are unlikely to be needed in day-to-day operations. The extensive modeling commenter proposes appears economically out of the reach of both the Division and most operators. Where such models are submitted to the Division, they will be made available to the public unless otherwise deemed confidential.*

0026-18

§1726.3(c)(5): “Corrosive potential fluids” should be replaced with “wall loss”.

***Response:** NOT ACCEPTED. This proposed section is specifically concerned with the effects of corrosion. There are many ways to mitigate wall loss associated with mechanical wear of the casing wall, but these do not mitigate corrosion, which is the main cause of casing thickness reduction over time.*

0026-19

§1726.3(c)(5) and (8): Commenter requests that subdivision (c)(8), (requiring analysis and risk assessment of hazards associated with the formation of hydrates and scale from the well stream) be reconciled with subdivision (c)(5) (requiring ongoing monitoring of casing pressure changes at wellheads, analysis of facility flow erosion, hydrate potential, individual facility component capacity and fluid disposal capacity). *Editor’s Note: (Subdivisions (c)(5) and (c)(8) are now listed in the proposed regulations as (d)(5) and (d)(8)).*

Response: *ACCEPTED.* Language related to hydrate potential has been removed from paragraph (5) so there is no overlap with the requirements of paragraph (8).

0024-34

§1726.3(c)(6), (7), and (11): These sections should be deleted as duplicative of the requirements in proposed §1726.7.

Response: *NOT ACCEPTED.* These proposed sections are an intentional cross-reference to the requirements of proposed section 1726.7. The planned monitoring activities are part of the comprehensive RMP and must be incorporated rather than be treated as standalone requirements.

0019-12

§1726.3(c)(7) and (8): While the proposed regulations refer to operating conditions and parameters, the regulations fail to specifically require written operating procedures for safely conducting activities including steps for each operating phase, e.g. normal operations, emergency operations, including emergency shut down procedures, such as when a leak is detected or during upset conditions; operating limits or parameters including consequences of deviation and steps required to correct or avoid deviation; safety and health considerations; safety systems and their functions. Additionally, there should be a specific training requirement for the operating procedures.

Response: *NOT ACCEPTED.* The detailed requirements suggested are too prescriptive and inconsistent with the performance-based approach that is central to the RMP requirements.

0026-20

§1726.3(c)(10): Commenter requests clarification as to which fire risk should be assessed, i.e. wild fire?

Response: *ACCEPTED IN PART.* For additional clarification of the broad nature of risk that must be considered, “explosion” has also been added.

NOT ACCEPTED. Nothing in the proposed regulations suggests that this fire risk should be limited to a single source, such as wild fire. The use of the word “fire” is purposely broad so as to include any and all potential risk associated with fires of any type from any source including well fires, wild fires, chemical fires, vehicle fires, grass fires, arson, etc.

0019-13

§1726.3(c)(12): As written, "safety training" is quite broad, and it is unknown exactly what type of training this refers to or what it entails. The regulations fail to specify if this safety training is for inspection, testing and maintenance activities, mechanical integrity testing, monitoring operations, emergency procedures, etc. The lack of clarity makes the requirement vague and ineffectual.

Response: *ACCEPTED IN PART. The reference to "safety training" in the proposed regulations has been removed and replaced with a requirement for "an effective training program with clearly stated goals." In addition, the operator will now be required to assess the risks associated with human factors, including the effectiveness of training and its impact on operations.*

NOT ACCEPTED. Risk assessments under the RMP will dictate what type of training will be required to mitigate hazards. The training requirements under the site-specific plan must be based on the threats and hazards identified by the risk assessments with a goal to ensure that all onsite personnel are participating in the ongoing management of risk and implementation of planned mitigation measures.

0024-35

§1726.3(c)(13): This section should be modified to a risk assessment of operations and maintenance (O&M) activities. Analyzing the threats from O&M will lead to considering prevention protocols that include safety training and equipment maintenance programs, as noted in API RP 1171. If this comment is accepted, subdivision (c)(14) should be deleted in its entirety.

Response: *NOT ACCEPTED. This proposed section is focused on those risk assessments and mitigation protocols which must be included in every plan. If the commenter-proposed language were used, it would suggest that there might be circumstances where a risk assessment would find that no training or equipment maintenance is required. As this result would be unacceptable to the Division, the minimum standard for inclusion of training and equipment maintenance programs is specifically outlined in the proposed regulations. The details of those programs, what is needed and when, should be based on the risk assessment, leading to the same outcome desired by commenter without weakening the regulatory requirement.*

0019-14, 0026-21

1726.3(c)(14): The proposed equipment maintenance program should not only include proactive replacement, but "proactive inspection, repair and replacement of equipment" or alternatively, "inspection and corrective maintenance."

Response: *ACCEPTED. Language has been added to this section to require proactive “inspection, repair and replacement” of equipment at risk of failure.*

0024-36, 0026-22

§1726.3(c)(16): The requirement to request notice from local land use agencies should be removed because the RMP review cycle would include review of proximate facilities, new and existing, as noted in subdivision (c)(2)(A), which would impact how the risk of a given well or facility is managed. In addition, commenters cannot be certain that compliance is possible, or that such a request would be fulfilled by local land use agencies, as commenters often do not receive notices on changes or modifications to local land use regulations. Further, local land use controls may often be preempted by or in conflict with state and federal regulations. Additionally, the information request should not imply local land use agencies have land use authority over certain operations of a facility.

Response: *NOT ACCEPTED. The requirement to request notice from land use authorities is intended to additionally enable awareness of planned development and land use in areas surrounding the project. Risk from and to future development is an important component of risk management that must be mitigated by monitoring and response when necessary. It is common practice for interested parties to monitor development permit activity and to place themselves on lists of persons who request notice about upcoming land use decisions. Even if this notice is only delivered by posting of information on a government website, there are no barriers to compliance for a proactive operator. Concerns that land use agency authority or jurisdiction over facility operations could be changed by a simple request for notice about government activity are unfounded. Monitoring of those development activities that may encroach on the project is an important part of the RMP.*

0024-37

§1726.3(d): If an operator varies from the risk mitigation protocols in its RMP, the operator will provide notice to the Division of the variance with justification. To effectuate this change, commenter recommends modification of this section to require notification only, eliminating the requirement for pre-approval of the variance in writing by the Division.

Response: *NOT ACCEPTED. PRC section 3181, subdivision (b), regarding the data and materials that must be submitted to the Division including the RMP, requires that*

the “operator shall not deviate from the programs, plans, and other conditions and protocols contained in the materials without prior written approval by the supervisor.”

0025-6

§1726.3(d): Commenter objects to the proposed rule in this section which would grant the Division broad authority to waive the preceding risk mitigation requirements. The Division should provide detailed guidelines, including examples, of when variances to the risk mitigation protocols would be appropriate or inappropriate. The proposed broad language invites abuse and threatens to undermine the purpose of the RMPs.

Response: *NOT ACCEPTED. The goal of this regulatory structure is to ensure that the minimum requirements are met, but also to ensure that new technologies and creative problem-solving can be leveraged by operators to improve safe performance. Thus, variances are considered appropriate any time an operator can demonstrate to the Division that the performance criteria have been met, provided that the Division agrees in writing. The allowance for these variances does not undermine the RMP, because any variance must be approved as part of the plan and would therefore be incorporated into its risk mitigation protocols. As required by statute, variance is not permitted without prior written approval from the Division.*

0017-6, 0019-15

§1726.3(e): There are no timeframe requirements regarding when the completed RMPs should be posted on the Division’s public internet website. Commenters suggest they are posted within 30 days.

Response: *NOT ACCEPTED. Documents will be posted by the Division to the website after they have been properly reviewed and finalized with the operator. Due to the many factors that can affect this review process, as well as the need to ensure that confidential information is properly protected, a timeframe for posting cannot be specified.*

0024-38

§1726.3(e): This section should refer to Public Utilities Code section 583 for requirements on handling confidential documentation.

Response: *NOT ACCEPTED. Public Utilities Code section 583 relates to documents submitted to the CPUC and does not apply to documents that operators submit to the Division.*

0030-15

§1726.3(e): Commenter encourages the Division to release drafts of completed RMPs, including their protocols, methodologies, and guidance, for public comment prior to approval. This is consistent with requirements in other dangerous industries. For example, Health and Safety Code § 25535.2 requires an agency to make a completed RMP available to the public for review and comment for a period of at least 45 days. A notice briefly describing and stating that the RMP is available for public review at a certain location shall be placed in a daily local newspaper or placed on the agency's website, and mailed to interested persons and organizations.

Response: *NOT ACCEPTED. The Division wants operators to continually review and update these plans in real-time based on changing site conditions and new information. The delay and cost associated with requiring public comment may discourage these necessary updates and delay needed mitigation activities. The goal of the Division is to work with operators in an ongoing process that focuses on risk assessments and mitigation with regular adaptation to changing conditions, lessons learned, and technology developed. A public comment process would vitiate this needed flexibility to change and improve. As required by statute, approved RMPs will be posted on the Division website, and the Division will always be receptive to public input.*

0030-52

§1726.3(e): Commenter is glad the RMPs will be posted on the Division's website. Risk assessment results as well as all verification, testing and demonstration results should also be made publicly available on the Division's website.

Response: *All components of an approved RMP that are not subject to confidential treatment will be posted on the Division's public website.*

1726.3.1 EMERGENCY RESPONSE PLAN (ERP)

0010-7

§1726.3.1: Commenter suggested edits to strengthen the Emergency Response Plan (ERP), as it is a very important component of the regulation, especially in light of the Aliso Canyon incident that initially sparked this rulemaking effort. Edits are based on the recommendations in the Regulatory Considerations guide, along with industry and standards guidelines like NFPA 1600 and CSA Z731-03. The specificity required by the edits would greatly increase the required rigor of ERPs, with additional focus on training, education, drills, communication, plan updates, and transparency. Specifically, commenter recommends that the plan "address minimum guidelines" rather than

“specify a schedule” and apply to all levels of the organization’s management and staff, as well as outside regulators, emergency responders and community stakeholders. It shall, at minimum, address: policy, goals and objectives of the plan; strategy, tactics, detailed risk assessment practices and business impact analysis; an appropriate-to-operation incident management system; a comprehensive hazard identification process; appropriate preventative and mitigative strategies and tactics; and well-designed procedures for potential emergency scenarios. In addition, the plan shall demonstrate: written action plans for all operational phases; recordkeeping programs; accident response measures; prepositioning and identification of required resources; provisions for damage assessment, response and communication; protocols for emergency reporting; specification of personnel roles; emergency contact information; and a protocol for public notice after a leak. The plan shall also include a robust training and education program; appropriate plans for exercises and drills; shall require annual review and updated submission for Division approval; will be subject to the California Public Records Act; and shall be posted on the Division website.

Response: ACCEPTED IN PART. The Division accepted suggested edits requiring consideration of harm to onsite personnel and affected communities, clarification of language regarding plan goals and objectives, the need for an incident response system, a more robust training requirement including a requirement to retain records of drills and training, and the need for a plan review period.

NOT ACCEPTED. The Division did not accept suggested edits requiring a business impact analysis, preventative and mitigative strategies in the ERP, a written action plan for all operational phases, a requirement to preposition all resources for all emergencies, and language specifying type and content of emergency drills and stakeholder participation. It is the intent of the proposed regulations that operators consult with local emergency response agencies in the development of their plans, as those agencies have expertise and experience in emergency response that the Division does not.

0017-11, 0030-55

§1726.3.1: It is not clear when a currently operating UGS facility must submit an ERP. It is recommended that they should be submitted within 60 days of approval of the regulations.

Response: ACCEPTED IN PART. The ERP is part of the RMP. Language has been added to require that RMPs be submitted within six months of the effective date of the proposed regulations. This would include the ERP.

0017-12

§1726.3.1: It is not clear how long DOGGR has to approve an ERP, and it is recommended that the review must be completed with 60 days of receipt.

Response: *NOT ACCEPTED. ERPs submitted to the Division will be of varying length and detail, depending both on the overall quality of the submission and the specific challenges and risks that exist at a site. This review process must be thorough to be effective and cannot be guaranteed within a specified timeframe.*

0030-21

§1726.3.1: Operators must be required to prepare, implement, and train each employee at the facility in the emergency response protocols.

Response: *ACCEPTED. A requirement for an effective training program with clearly stated goals and specification of the type of training and scenarios addressed has been added to the proposed regulations.*

0035-1

§1726.3.1: It is very important to consider the danger of earthquakes and the multiple failures within these facilities that are likely to happen from this single cause. Very likely that an earthquake could cause multiple casing problems, valve problems, all happening at once. To ensure that we have dealt with all possible causes of failure, earthquake needs to be in the ERP.

Response: *ACCEPTED. The need to evaluate seismicity and its effect on storage operations is a specific requirement of the RMP. As an element of the RMP, the ERP will include mitigation measures and response activities designed to reduce damage to well infrastructure and respond to damage, threats and hazards created by a seismic event as identified and quantified in the RMP.*

0019-16

§1726.3.1(a): Regarding the schedule for carrying out drills to validate the ERP, the frequency of the drills should be specified, and the distinction between table top and hands on drills be made clear.

Response: *NOT ACCEPTED. Dedicated and local emergency response entities, such as fire and hazardous material responders, are better suited to advise operators on the specifics of their ERP. As part of the required consultation with these local agencies during plan development, operators and emergency response experts should make*

these determinations based on the specific risks and responses that will be appropriate in each emergency situation. The Division will ensure that these plans are in place and check for compliance with the requirements during project review, including ensuring that input from local emergency response entities has been incorporated and plan components are supported by appropriate evidence of efficacy.

0019-17

§1726.3.1(a): In addition to the local first responders, the ERP should also be provided to the Unified Program Agency for review and input. The preparation, elements, submittal and review of the ERP should be consistent with Health and Safety Code (H&SC), Chapter 6.95, Article 1, that is already required of the facility.

Response: *NOT ACCEPTED. The Division encourages local emergency response entities and operators to coordinate the development of ERPs with any agency or source of expertise that may make for the most effective plan at each project location. The Division agrees that any ERP generated by the operator must simultaneously meet the requirements of these proposed regulations and any other requirement imposed by law, but those requirements do not need to be duplicated in the proposed regulations.*

0024-40, 0026-9

§1726.3.1(a): Providing local first responders a reasonable opportunity to consult on or review an operator's ERP is more appropriate than mandating a prescriptive review period because circumstances may dictate that changes to the plan be made and effected more quickly than in 30 days. Consultation is more consistent with the language of SB 887.

Response: *NOT ACCEPTED. A timeframe for local review is provided to ensure ERPs can be completed within a reasonable timeframe. Without a timeframe for local participation, this period could become unreasonably extended. If the local agency has responded, but discussion of the ERP is continuing after 30 days, then the Division would expect the operator to continue to work with the local agency to receive its input. Where a local agency fails to respond within 30 days, the operator should proceed with development of its ERP.*

0030-23

§1726.3.1(a): Local community groups and people who live within 1 mile of a facility should be provided an opportunity to provide input on ERPs, in addition to local responders. Commenter recommends a 45-day public comment period with publication

of notice in a local newspaper, release via the agency's website, and mailing to interested persons and organizations.

Response: *NOT ACCEPTED. ERPs are prepared and implemented by experts and operator staff who are trained in and knowledgeable about emergency response. This includes emergency response entities, who are likely to be the first responders to an emergency and who have specific expertise in developing good response plans. As part of the RMP, the ERP will be posted on the Division website once it has been approved.*

0030-24

§1726.3.1(a): The operators must be required to provide local community groups and people who live within 1 mile of a facility access to their ERPs as well as contact information in case of emergencies. Plans and reports of plan activities should be publicly available.

Response: *ACCEPTED IN PART. ERPs are prepared and implemented by experts and operator staff who are trained in and knowledgeable about emergency response. This includes emergency response entities, who are likely to be the first responders to an emergency and who have specific expertise in developing good response plans. As part of the RMP, the ERP will be posted on the Division website once it has been approved.*

0024-39

§1726.3.1(a) and (b): There is potential jurisdictional conflict as ERPs overlap with CPUC and PHMSA jurisdictional assets. A requirement for Division approval could also conflict with current Part 192 (API RP 1171) requirements or future requirement changes or additions. Commenter recommends edits limiting the requirement to submission of a plan consistent with API RP 1171.

Response: *NOT ACCEPTED. PRC section 3181 specifically requires operators to submit an RMP, including the ERP element, to the Division for approval. It is common for state regulations to be more stringent in their requirements than Federal regulations, thus an ERP that meets Division requirements should also meet PHMSA requirements. ERPs that pertain to well safety and well area safety should easily mesh with ERPs generated for the CPUC as both entities are concerned with hazard identification, risk assessment, effective mitigation, and emergency response.*

0026-24

§1726.3.1(b)(4): "Wellhead" should be added in front of "equipment failures" to be consistent with API RP 1171.

Response: *NOT ACCEPTED. The Division is concerned with all equipment failures and their potential impact on the well, not just wellhead equipment.*

0026-25

§1726.3.1(b)(6): Releases or potential release of hazardous material that are reasonably believed to pose a significant present or potential hazard to human health and safety, property, or the environment are reportable to the California Governor’s Office of Emergency Services and Certified Unified Program Agency . (19CCR 2703; HSC25507(a)). At the beginning of this section commenter suggests adding the words “Reportable releases including...”.

Response: *NOT ACCEPTED. The suggested change would limit the planned response to leaks and well failures to those that reach the level of “reportable.” For the purposes of the ERP, however, there may be non-reportable leaks or well failures that would still require emergency response. The goal of the Division is to ensure that all leaks and well failures are considered potential emergencies and are analyzed and planned for as part of the ERP, even if they are not specifically reportable.*

0025-8

§1726.3.1(c): The Division should require operators to estimate the timeframes for deploying necessary personnel and equipment. This analysis may reveal important gaps in the availability of local personnel and equipment, and is also important information to communicate to any nearby residents and first responders.

Response: *NOT ACCEPTED. Operators will do this as a part of their ERP development when making determinations regarding the appropriate repositioning of equipment and personnel as required by the proposed regulations. These timeframes may change depending on circumstances such as time of day, traffic, or weather. Operators will also learn about the effect of these variables during their emergency response drills and will be able to adjust based on actual conditions rather than relying solely on preliminary estimates. A more specific requirement is not needed.*

0015-24

§1726.3.1(c)(3): Commenter recommends that the ERP include the requirement to eliminate nuisances and comply with local and regional air quality rules as well as to protect public health.

Response: *NOT ACCEPTED. Protection of public health is a necessary component of the RMP, and therefore appropriate protocols for the ERP will be determined based on risk assessment. Steps to comply with other agency rules may be included in the ERP. Existing legal responsibilities do not need to be reinforced by a Division regulation.*

0024-41, 0026-27

§1726.3.1(c)(3): Commenters suggest the removal of “surprise” from this section as it could lead to drills that unduly interrupt operations at critical times without an appreciable benefit over scheduled drills. Further, unannounced surprise drills by non-operator affiliated individuals could result in serious safety and security hazards at gas storage facilities, as operators need to exercise control and access to their facilities at all times. “First responders” should be referred to as “emergency response entities.”

Response: *ACCEPTED. The requirement for “surprise” drills has been removed. The use of “first responders” has been changed to “emergency response entities” throughout the proposed section. The requirement to drill and provide an opportunity for drills initiated by emergency response entities, with appropriate notice, remains unchanged.*

0026-26

§1726.3.1(c)(3): This section should be edited to replace “leaks” with “reportable releases” and expand the requirement to protect public health “and safety”.

Response: *ACCEPTED IN PART. The language “and safety” has been added. NOT ACCEPTED. It is the goal of the Division to ensure that ERPs are prepared for all emergencies including significant leaks, and this not necessarily limited to leaks that are otherwise required to be reported.*

0030-22

§1726.3.1(c)(3): Operators should be required to run at least *annual* safety drills with all employees (not merely provide a schedule for safety drills). In addition, it should be a requirement that safety drills be witnessed by DOGGR and Fire Department staff or other first responders.

Response: *NOT ACCEPTED. A requirement for drills has been included but should be developed based on the risk assessments rather than a specific schedule. A small operation may be so successful at emergency response that a drill once every two years is sufficient, while a larger operation with higher staff turnover may need a drill once every quarter. The appropriate drill frequency should be determined by the level of risk at the facility based on site-specific characteristics and actual operations. Local*

emergency response entities will have the ability to initiate drills and the operator may also invite them to participate in operator scheduled drills. As evaluating effective emergency response requires technical expertise outside of the Division's scope, a requirement for a Division witness at these drills is not appropriate.

0015-25, 0019-18

§1726.3.1(c)(9): In the case of a large, uncontrollable leak that may impact a community, notification must be done as soon as onsite personnel can safely make the notification (alternatively, within 6 hours). 48-hours' notice is unreasonable, unacceptable, and inconsistent with the regulations that require the operator to notify the Division immediately.

Response: *NOT ACCEPTED. PRC section 3181, subdivision (a)(2)(A)(i), requires that an operator's ERP include a protocol for public notice of a large, uncontrollable leak to any potentially impacted community, as defined in the RMP, if the leak cannot be controlled within 48 hours of discovery by the operator. In the immediate timeframe following discovery of a leak, onsite personnel are focused on determining the best way to control that leak. Required immediate notification to the Division and emergency responders allows for a coordinated "all hands-on deck" approach to ensure that everyone with the potential to provide needed resources is working towards controlling the leak and mitigating harm as quickly as possible. Throughout this initial response period, information is being gathered about the leak and the potential impact to surrounding communities is being evaluated. A determination that the leak is uncontrollable is not, therefore, immediate. The 48-hour timeframe for public notice ensures that initial efforts are focused on mitigation, sufficient time is provided for evaluation of risks and impacts. If emergency response personnel determine that a significant risk to the public is imminent, nothing in the proposed regulations would prevent earlier notification to the affected community as needed to protect public health and safety.*

0015-26, 0052-9

§1726.3.1(c)(9): The public protocol required under this section should be subject to public review and comment by relevant community groups, schools, places of worship, and interested individuals, etc. Commenters suggest 30 days (or 60 days) as the appropriate period for this review, similar to the period of time allowed for comment by local emergency response entities.

Response: *NOT ACCEPTED. The RMP, including the ERP, will be available on the Division's public website after it has been approved, as required by PRC section 3187.*

However, a requirement for public input is not appropriate, as it can unreasonably delay plan implementation and activities. Local emergency response entities will have an opportunity to comment and provide input on the plans.

0025-7, 0029-2

§1726.3.1(c)(9): The terms “large” and “uncontrollable” are vague and undefined. If a community may potentially be impacted by a leak, it should be notified as soon as possible, regardless of the size of the leak or ability of the operator or others to bring the leak under control. Commenters request that widespread immediate public news notification be made a part of every leak and release of gas over 2 parts per million (ppm). Immediate notification will allow members of the community to make a decision to stay or leave the area, and it will also make it clear just how frequently this happens, possibly further encouraging natural gas suppliers to be less slipshod at their operations.

Response: *NOT ACCEPTED. PRC section 3181, subdivision (a)(2)(A)(i), requires that an operator’s ERP include a protocol for public notice of a large, uncontrollable leak to any potentially impacted community, as defined in the RMP, if the leak cannot be controlled within 48 hours of discovery by the operator. It is a recognition of the fact that it takes time to evaluate a leak and determine the potential harm and appropriate response. The Division must be notified immediately so that it can assist in this evaluation and ensure appropriate corrective and mitigating actions are taken. Other local and state agencies must also be notified. Where the Division, the operator, local emergency response entities, or another state agency determines that the public is at risk, notification will be made as soon as it can be done responsibly. This proposed subdivision requires a notification after 48 hours if the leak cannot be controlled, this does not prevent the response team from releasing information to the public more quickly if needed to protect public health and safety.*

0030-20

§1726.3.1(c)(9): Commenter is pleased that the Division laid out more detailed protocols for ERPs than the earlier draft of the regulations. Commenter wants to emphasize the importance of the ERPs including clear outreach and enhanced public information protocols both for leaks that cannot be controlled within 48 hours and emergencies that require a faster response or shelter-in-place orders.

Response: *The Division also believes these plans are important and encourage the operators to consult with local emergency response entities who have expertise in these areas to ensure their ERPs are detailed and include responses to all potential*

scenarios. The public information protocol required by statute will be enhanced by cooperation with these local experts, who will also take the lead in determining the appropriate public notice in case of an emergency affecting nearby residents.

0025-9

§1726.3.1: It is critical that the Division be notified as soon as possible when a potential emergency is discovered. It is also critical that this information be shared with the public as soon as possible, especially any members of the public that may be impacted by that emergency. Commenter recommends the addition of language to this section requiring notification to the Division as soon as possible, but no later than 24 hours following the discovery of an emergency and requiring the Division to post a notice of emergency on its website with facility emergency 24-hour contacts, including phone numbers and e-mail addresses for lead personnel.

Response: *NOT ACCEPTED. The proposed regulation requires that an operator's ERP include protocols for emergency response reporting and response to appropriate government agencies, and proposed section 1726.9 requires reporting significant well leaks to the Division. In the case of some emergencies, Division participation may not be a priority. For example, a vehicle fire would be covered under the ERP and would be considered an "emergency," but there is no immediate value to notice to the Division as it is not involved in response to vehicle fires unless there is a collision with or damage to a well or well infrastructure. An employee injury would similarly be an "emergency" for which there is no immediate benefit to Division notice or participation.*

0025-10, 0030-72

§1726.3.1: ERPs must specify a process for periodic review and reassessment at least every two years, or alternatively, every five years. Commenters recommend a comprehensive process for ongoing and continuous plan review and reassessment that is flexible and iterative. DOGGR should review standards and approaches of other hazardous industries and their regulatory bodies, including the California Interagency Working Group on Refinery Safety, the Chemical Safety Board, and a proposed rule from the EPA under the Clean Air Act which includes enhanced requirements for emergency preparedness.

Response: *ACCEPTED IN PART. A requirement for regular evaluation and update of the ERP is already included in the regulations, language has been added to also require review and update after key personnel changes, no less than once every three years. As part of the RMP, the ERP is also subject to the review and update requirements of*

proposed section 1726.3, which includes a schedule for regular review and update of mitigation protocols including emergency response activities.

1726.4 UNDERGROUND GAS STORAGE (UGS) PROJECT DATA REQUIREMENTS

0018-5, 0030-77, 0039-4

§1726.4: Commenters relate stories in which a well “kill” failed, and kill fluid was sprayed into the air and dispersed into the community, exposing people to elevated levels of barium, a constituent in the barium sulfite used in kill attempts. The regulations do not pose any restrictions of the use of these fluids, not even a requirement that the chemical constituents be disclosed. Full analysis of any kill fluid that may be used in response to a future leak should be required.

Response: *NOT ACCEPTED. The content of kill fluid is generally known as it is used throughout the industry and is provided by a manufacturer who must disclose the contents to the operator. Existing rules require Material Safety Data Sheets for all hazardous chemicals used in a workplace, and this would include kill fluid. The Division does not have a regulatory use for an analysis of an individual batch of kill fluid as the associated hazards are known and will be incorporated into the RMP. A failed kill attempt, resulting in a dispersal of fluid to surrounding areas, would be an appropriate accident scenario for inclusion in the ERP and mitigation measures for such an event should be prepared.*

0027-6

§1726.4: Every year, gas companies account for gas that is no longer present in their gas storage facilities. Sometimes the gas is used by the gas company and other times the gas is lost during blowouts and leaks. The volume of gas lost and categorized by gas companies as “unaccounted for” is incredibly important to know and to understand the integrity of the gas company’s operations and wells. In the example provided, the operator stopped recording the unaccounted-for-gas in 2003, which is curious because it would seem that shareholders would want to know the amount of gas that is “unaccounted for.” In light of the importance of lost gas, DOGGR should be requiring gas storage operators to account for “unaccounted for” gas.

Response: *ACCEPTED. Proposed section 1726.7(b) requires operators to monitor the material balance of a UGS project’s storage reservoir relative to the original design and expected reservoir behavior.*

0030-26

§1726.4: Where well stimulation or fracking has occurred, or will occur, at a gas storage project or a well in the AOR, there should be extra requirements for monitoring to detect loss of integrity. These should, at a minimum, reflect the API Handbook's list of monitoring practices associated with well stimulation.

Response: *NOT ACCEPTED. Monitoring for integrity loss is already required, including a real-time monitoring system and regular integrity testing. Hazards associated with well stimulation activities would be assessed and mitigated as part of the RMP.*

0030-27

§1726.4: DOGGR must publicly provide information on all well stimulation activities that have occurred and are occurring at gas storage facilities, including fracking. Well stimulation poses excessive risks to well integrity, geologic integrity, and water, and the public is entitled to full disclosure of these dangers.

Response: *ACCEPTED IN PART. Under existing regulation section 1777.4, UGS operators must already report all well treatments, including acid and pressure treatments, to the Division within 60 days of completion. The information provided is maintained in the Division's database of well information, which is available to view via the Division's website.*

0030-32

§1726.4: Because acidizing, hydraulic fracturing, and other enhanced extraction measures occur in UGS facilities, the regulations must require operators to disclose the chemicals and other hazardous substances used during injection and extraction processes for all UGS projects as part of their data requirements.

Response: *NOT ACCEPTED. Under existing regulation section 1777.4, UGS operators must already report all well treatments, including acid and pressure treatments, to the Division within 60 days of completion. The information provided is maintained in the Division's database of well information, which is available to view via the Division's website. Pursuant to PRC section 3160, subdivision (o), well stimulation treatments used for routine maintenance of wells associated with underground storage facilities are not subject to the requirements of PRC section 3160.*

0030-57

§1726.4: Ongoing reservoir performance monitoring programs, and a geologic characterization that encompasses the intended reservoir rock and sealing

mechanisms, the vertical interval above and below the intended reservoir, areas where gas could potentially migrate, and the areas adjacent to the intended reservoir where potential entrapment of migrated gas could occur. The depths of groundwater and locations of surface waters should be delineated. Locations of abandoned wells, underground disposal horizons, mining, and other industrial activities should be mapped. Surface topography and land use should be included in the evaluation where topography and land use may impact storage surface facilities and/or subsurface integrity. The reservoir rock itself should be characterized including its lithology, geo-mechanical competency, porosity, permeability, homogeneity, isotropy, and residual pore fluid saturations. A competent and impermeable caprock, located above the intended gas-filled reservoir should be identified and evaluated for controlling the upward movement of the stored natural gas. The basal and lateral sealing mechanisms should be identified and evaluated for controlling movement of the stored gas. Anomalous geologic features such as faulting, natural fracturing, folding, and unconformities should be evaluated in terms of their potential for compromising reservoir integrity.

Response: *ACCEPTED IN PART. The information commenter specifies is included in the extensive data which is required from all gas storage operators under the proposed regulations. For existing projects, this data will be used to identify potential hazards for management under the RMP including the need to provide additional mitigation or shut-in any wells that pose a hazard based on geologic conditions, surrounding land uses, and/or changes in subsurface integrity.*

0030-58

§1726.4: The site characterization data should include data on seismic activity and compaction/subsidence.

Response: *NOT ACCEPTED. Seismicity and other geologic hazards, such as subsidence, must be considered as part of the RMP. Data will be required to support any quantitative analysis regarding these hazards.*

0030-62

§1726.4: Injection pressures of any fluid or gas must be known. In addition, it is imperative that operators report what type of injections are occurring—including fracking, steam, gas, gravel packing, acidizing, and all chemicals that are injected. Operators should be required to report all information listed in the South Coast Air Quality Management District Rule 1148.2 including information on all well stimulation activities.

Response: *NOT ACCEPTED. Operators of UGS facilities are already required to submit monthly reports on production and injection data, and under existing regulation section 1777.4 UGS operators must report all well treatments, including acid and pressure treatments, to the Division within 60 days of completion.*

0030-73

§1726.4: The regulations must ensure that operation pressures do not exceed the virgin pressure of the reservoir.

Response: *ACCEPTED. This is part of the analysis that uses rock mechanics to determine the geologic properties of the reservoir, which is then used to determine maximum allowable operating pressure.*

0018-1

§1726.4(a): It is unclear how the operator and/or the Division will determine whether or not the UGS project will cause damage to life, health, property or natural resources. The regulations should explicitly state the environmental and health assessment activities that will be carried out, and the process by which related data and findings will be publicly available.

Response: *NOT ACCEPTED. The specific assessments and data requirements appropriate for each project will be included in the RMP based on the risks associated with site-specific characteristics and planned operations. The proposed regulations include a detailed list of the minimum data that must be submitted and require submission of additional information as may be requested by the Division. As required by PRC section 3187, complete project data and approved RMPs will be available on the Division's public website.*

0018-2

§1726.4(a): The Division must require all UGS projects to review potential health risks and community impacts associated with their operation, including, but not limited to: fugitive gas emissions into outdoor air; migration of natural gas out of the storage formation, presenting a risk for groundwater contamination and/or subsurface vapor intrusion; and odor impacts that can negatively impact quality of life, and cause symptoms such as headaches, nausea, respiratory irritation and irritation of the eyes, nose and throat.

Response: NOT ACCEPTED. The proposed regulations do not attempt to delineate all the potential risks, hazards, and consequences associated with a gas storage operation. Instead, operators must evaluate the risks of their specific operation, as specified in proposed section 1726.3.

0010-36

§1726.4(a) and (a)(5)(C): Project data requirements revisions are recommended, including the proposed mechanical integrity testing methodology. Additions should include methods for demonstration of integrity and additional features to be added to the geologic characterization including identification of groundwater, flow zones, and other hydrocarbon-producing reservoirs. Revisions should also be made to the geologic cross section language to ensure representative well logs are used, and to require additional information which may be requested by the Division including isopachs, isogors, isobars, and 2D or 3D seismic reflection surveys. Additional information should be limited to “significant” features only.

Response: ACCEPTED IN PART. The proposed subdivision was revised to focus on pathways for migration of fluids instead of gas. When dealing with dry reservoirs, an isobar may be a reasonable requirement. Isobar has been added to the examples in this proposed section.

NOT ACCEPTED. Methods for demonstration of mechanical integrity are determined based on risk assessment as part of the RMP and as specified in proposed section 1726.6. The geologic cross sections provided for in the current regulations are sufficient for the Division’s needs and the representative logs recommended are already required in the subsequent section. Isogors and isopachs would not be appropriate. All relevant features should be included, not limited to “significant” features.

0024-43

§1726.4(a)(2) and (a)(6)(D): The data requirements should only extend to records for installed equipment. Revisions to existing equipment would be included as part of the well rework history and updated wellbore schematics submitted to the Division.

Response: ACCEPTED. Language has been modified to remove the reference to “proposed” equipment.

0024-44

§1726.4(a)(3): Only practiced methods need to be on file as proposed methods are not finalized and could lead to erroneous record keeping. The word “proposed” should be replaced with the word “current”.

Response: *ACCEPTED IN PART. The word “proposed” has been removed from this proposed section so that it simply says “produced water disposal method.” This captures both the current water disposal method, and any other methods that the operator may intend to use.*

0010-44, 0025-11, 0027-17, 0030-4, 0046-7

§1726.4(a)(4)(A): Although state regulations appear to prohibit fracking, it still occurs in gas storage wells. The proposed regulations, which now exempt gas storage wells from Section 1724.10(i), must make clear that any injection above fracture pressure is expressly prohibited. Currently, proposed section (a)(4)(A) indicates that pressure limits “shall not exceed the design pressure limits of the reservoir, caprock, wells, well heads, piping or associated facilities.” This paragraph should expressly state that pressures may not exceed fracture pressure, in keeping with current state regulations. In addition, the term “routine maintenance” in PRC § 3160(o) is not defined. It is likely that operators will interpret the term broadly and therefore interpret the combination of Sections 3160(o) and 1724.9(a) and (b) to mean that they are only subject to a ban on injection of gas at high pressures; neither SB 4 nor the proposed regulations ban fracking in these wells. The permanent regulations must clarify the meaning of “routine maintenance” to avoid this broad interpretation by operators.

Response: *ACCEPTED IN PART. Language prohibiting injection pressure that exceeds the fracture pressure of the reservoir or confining strata was added to proposed section 1726.4 in subdivision (a)(4)(A).*

NOT ACCEPTED. Under existing regulation section 1777.4, UGS operators must already report all well treatments, including acid and pressure treatments, to the Division within 60 days of completion. The Division does not see a need for further definition of “routine maintenance.”

0024-45

§1726.4(a)(5)(C): The data collection requirements should be revised to specify only data that can be quantified, such as lithology and sealing mechanisms. The risks associated with utilizing a reservoir for underground storage are evaluated as part of the RMPs. Non-specific language in this section requiring “any information” to ensure no “adverse effect” and “potential” migration pathways and/or gas entrapment should be deleted.

Response: *NOT ACCEPTED. This proposed section is focused not just on risk assessment, but on ensuring that all pertinent data is on file regarding the reservoir and*

storage project. Where a new field is being considered, the comprehensive geologic characterization will be needed to evaluate the storage reservoir and its competency. For existing operations, this data will ensure that evidence is on file supporting reservoir competency and providing a baseline for any potential changes that may occur in its ability to provide confinement of fluids. Although quantitative data is preferred, complete data necessarily includes items that cannot be strictly quantified.

0024-46

§1726.4(a)(5)(C): A risk assessment should be completed to determine if gathering the information specified in the subparts of this section is necessary as part of the geologic characterization, rather than those items being always required.

Response: *NOT ACCEPTED. The data identified in the proposed subdivision are required for every project because they are needed for proper evaluation of UGS activities to determine the level of risk. Operators should already have this information available in compliance with existing requirements.*

0025-12

§1726.4(a)(5)(C): Fluids other than the injected gas are likely present in the gas storage reservoir and the other formations in the geologic system that comprise the gas storage project. Such fluids may include but are not limited to residual oil where storage takes place in depleted hydrocarbon reservoirs, other fluids that may have been injected into the formation as part of hydrocarbon production operations (e.g. EOR or pressure maintenance operations), and connate water. These fluids may also have an adverse effect on the project or public health and the environment and operators should be required to analyze how all subsurface fluids, not just injected gas, may migrate through the subsurface as a result of gas storage activities. This section should be modified to include geologic characterization “including but not limited to the caprock” and information that may be required to ensure that “any other reservoir fluids” do not have an adverse effect or pose a threat.

Response: *ACCEPTED IN PART. Language related to “any other reservoir fluids” and the replacement of the word “gas” with the word “fluid” is accepted. NOT ACCEPTED. The caprock is included as part of the sealing mechanisms, which must be evaluated as part of the geologic characterization. Its specific inclusion here would be duplicative.*

0025-13

§1726.4(a)(5)(C): It is important that maps prepared in support of geologic characterization show all relevant features that may interfere with or enhance containment of stored gas, so that the Division and the public have access to complete and accurate information when assessing the adequacy of the geologic system. The requirements should be modified to include structure contour maps indicating faults and other lateral containment features and the base of the caprock, top of the caprock, and base of the lower most USDW; an isopach map including subzone and caprock; at least four structural dip and strike cross sections illustrating major structure features (i.e. faults, folds etc.) and extending across the AOR; and at least four stratigraphic cross sections, parallel and perpendicular to depositional strike, illustrating the areal extent and vertical thickness of the reservoir and caprock, through at least four gas storage wells and extending across the AOR and the areas immediately adjacent, as well as porosity and permeability maps of the caprock and any other confining zones.”

Response: *ACCEPTED IN PART. The Division has replaced the term “caprock” with “confining strata” throughout the proposed regulations. This change expands the maps requirement to include all the areas of concern to commenter. Language specifying structure dip and strike cross sections was also added. NOT ACCEPTED. Faults and lateral containment features are already included in the proposed regulations. Additional data subsections recommended by commenter are already included or are not needed for the Division’s regulatory purposes.*

0027-12

§1726.4(a)(5)(C): The geological studies should be prepared in such a way as to determine the migration of gas underground both in the reservoir and in aquifers. Without this additional requirement, the monitoring wells required in proposed regulations section 1726.7 are useless because the direction of migration is unknown (i.e. how do you know where to place a monitoring well if you don’t know the migration of underground fluids?) Thus, there should be explicit standards that set for the evidence of what is needed to confirm that the reservoir’s geological characteristics are safe.

Response: *NOT ACCEPTED. The language of this proposed section already specifies that the geologic characterization must identify potential pathways for fluid migration and areas or formations where potential entrapment of migrated fluid could occur. These performance standards set the minimum requirement for demonstration that fluids will not migrate outside the intended zones. A more prescriptive listing for specific data is not required.*

0021-5

§1726.4(a)(5)(C)(i): New rules for RMPs should require structure contour maps on all active or potentially active faults within gas storage fields. These maps should show the depth values of all intersections of wells and faults.

Response: *NOT ACCEPTED. These maps would be excessively costly for operators to produce with limited value to the Division. The operator is required to consider the risk and plan to mitigate the effect of any seismic activity as part of its hazard analysis for the RMP. Structure contour maps may be helpful to inform that analysis, but are not needed for the Division's regulatory purposes.*

0021-6

§1726.4(a)(5)(C)(iii): New rules for RMPs should require that sections be constructed in such a manner as to show the total slip (displacement) on active and potentially active faults that intersect storage field wells.

Response: *NOT ACCEPTED. The assessment of risk to individual wells associated with seismicity as part of the RMP does not require a detailed analysis of displacement on all faults, unless that fault is a reservoir confining mechanism. The operator must evaluate the risk of seismic activity and plan to mitigate any hazards, but comprehensive analysis of every fault is not necessary.*

0026-28

§1726.4(a)(5)(C)(iv): Commenter supports identifying and labeling the TDS boundaries however suggests removal of "aquifers with" from this section. This change would be in-line with the proposed UIC regulations definition of groundwater in Section 1720.1(c) and 1720.1(j) and UGS Projects Section 1724.4.1(a)(1)(D) and 1726.4.1(a)(1)(E).

Response: *ACCEPTED. "Aquifers with" has been removed from this proposed section.*

0026-29

§§1726.4(a)(5)(C)(v) and 1726.4(c): Commenter requests clarification of what compatibility of 3D modeling program and maps is required.

Response: *NOT ACCEPTED. There are no technical specifications for these requirements. Any technology which can produce meaningful models and maps that communicate the needed information is acceptable. If an operator has a program it is*

considering using and is concerned it may not meet regulatory requirements, they are encouraged to contact the Division to confirm that the output will be acceptable.

0025-14

§1726.4(a)(5)(C): Knowing the geomechanical properties of the geologic system is crucial to determining the appropriate maximum injection and storage formation pressures. Commenters recommend a data requirement for the geomechanical properties of the storage reservoir and caprock(s) including fracture pressure, ductility, rock strength, fluid pressures, principal stress orientations and magnitudes.

Response: *NOT ACCEPTED. Proposed subdivision (a)(5)(C) requires a comprehensive geologic characterization including any information that may be needed for the safety of the project. The suggested data requirements would not be necessary in every case*

0025-15

§1726.4(a)(5)(D): To protect actual and potential sources of drinking water, gas storage should not be allowed in zones that meet the federal definition of an Underground Source of Drinking Water (USDW). commenter recommends the requirement for reservoir fluid data specify that the data on water quality should “include but is not limited to TDS,” and to include language specifically prohibiting storage in zones containing USDWs.

0030-29

§1726.4(a)(5)(D): With regard to reported data, mere reporting of “water quality” is inadequate. Operators should be required to submit a detailed numerical groundwater model and aquifer tests to ensure that injection and storage will not affect supplies of potential domestic or beneficial use water.

Response to 0025-15, 0030-29: *NOT ACCEPTED. The proposed regulation would already require the operator to demonstrate that the UGS project will not cause damage to life, health, property, natural resources and the environment, and proposed subdivision (a)(5)(C)(iv) requires data regarding groundwater quality in the gas storage zone. If the Division is unsatisfied with the water quality information provided by the operator, it will request additional data.*

0018-3, 0030-60

§1726.4(a)(5)(E): The map of the AOR should include an inventory and description of surrounding land use, including residential, commercial and industrial zones, as well as

nearby schools, hospitals and daycares. The proximity of sensitive populations is critical to the Division's review of potential health risks and community impacts.

Response: *NOT ACCEPTED. The purpose of the data requirements in this proposed section is to ensure the ongoing geologic competency of the reservoir during project operations so as to prevent migration of fluids outside the approved zone(s). The impact of and to surrounding land use must be considered as part of the RMP.*

0025-16

§1726.4(a)(5)(E): Special steps must be taken to ensure that all wells in a gas storage field have been identified. Given California's long history of oil and gas production, locating existing wells – in particular plugged and abandoned wells – may be challenging and require the use of multiple detection methods. Failure to identify orphaned or improperly constructed or abandoned wells can result in leakage. For example, improperly abandoned wells at the Montebello UGS facility in Los Angeles leaked natural gas to the surface, resulting in the facility eventually having to be decommissioned, but not before homes had to be abandoned and torn down in attempts to repair the leaking wells. Commenters recommend the addition of language to require operators to “develop, submit and implement a plan to identify all wells within and adjacent to the area of review.” The plan must include four stages of investigation: Historical Record Review, Site Reconnaissance, Aerial and Satellite Imagery Review, and Geophysical and Air Emissions Surveys.

Response: *NOT ACCEPTED. The types of investigations that the commenter suggests may be required on a case-by-case where there is some indication that there may be an undocumented well in the area of review, but requiring all of these investigations for every area of review would be unwarranted.*

0025-17, 0027-29, 0030-30

§1726.4(a)(5)(F): The proposed regulations remove some of the previous requirements for casing diagrams. Why is DOGGR protecting gas companies in the wake of the blowout in Aliso Canyon? For instance, DOGGR's current regulations require an operator to provide casing diagrams including cement plus of **all** idle, plugged and abandoned or deeper zone producing wells within the area affected by the project. The proposed regulations would drop this requirement – DOGGR would now only require casing diagrams for wells that are in the same or deeper zone. Even wells that do not intersect the intended reservoir(s) or caprock can act as conduits for gas to migrate into groundwater or the atmosphere if gas migrates beyond the vertical and/or lateral confining zone(s) and encounters shallower wells lacking mechanical integrity. This

situation occurred in 2001 at an underground natural gas storage facility in Hutchinson, Kansas, resulting in multiple explosions and two deaths. The Kansas Geological Survey determined that gas initially leaked out of a gas storage well due to a casing failure, then migrated both vertically and laterally through the subsurface, eventually encountering shallow, poorly abandoned brine wells. At a minimum, casing diagrams should be required for all wells within the AOR that penetrate the caprock.

Response: NOT ACCEPTED. *The requirements for casing diagrams apply to all wells that are in the AOR and that are in the same or deeper zone as the gas storage reservoir. This would include idle, plugged and abandoned, and deeper zone wells within the area affected by the project. The shallow wells which caused the leak in Kansas were several miles away from the project. Commenter's proposed requirements would not have prevented that problem, which was ultimately about the migration of gas out of the zone through a faulty gas storage well. The proposed regulations are appropriately focused on those wells that intersect the zone and would be the primary concern for fluid migration outside the confining strata.*

0025-18

§1726.4(a)(5)(F): Commenter objects to the proposed requirements as being insufficient to ensure that plugged and abandoned wells will not act as potential conduits for fluids to migrate outside of the approved gas storage zone. The proposed rules also fail to include steps that must be taken in case of plugged and abandoned wells don't meet the requirements. Commenter recommends that the that the final sentence of this subsection be struck and provides language outlining detailed requirements for plugging and abandonment.

Response: NOT ACCEPTED. *The standards for evaluation of wells within the area of review have been moved to a separate section 1726.4.2, and the performance standard remains clear: the review must ensure that wells within the AOR will not be a potential conduit for fluid migration outside the approved gas storage zone. Proposed section 1726.4(a)(5)(H) provides, "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," and similar provisions are included in proposed section 1726.4.2. The default requirement for 100 feet of cement is sufficient, and rework of a well is required if there is reason to believe that poor quality cement makes the well a potential conduit.*

0022-9

§1726.4(a)(5)(G): If the requirement for “identification of all wells in the area of review” includes water wells that other landowners have drilled, gas storage operators are unlikely to have this information and it may be very difficult to obtain.

Response: *ACCEPTED. Language has been added to this section to limit the identification of wells to those wells “associated with oil and gas production” that are within the AOR, but that are not in the same or a deeper zone as the project.*

0026-30

§1726.4(a)(5)(G): Commenter believes this section as written includes shallow wells and is in conflict with the definitions in section 1726.1.

Response: *NOT ACCEPTED. This section discusses wells which are within the AOR, but not in the same or a deeper zone as the gas storage project. This would include shallow wells, as intended. Identification of such wells is necessary as the information may be relevant to the AOR evaluation and various hazard evaluations in the RMP.*

0024-47

§1726.4(a)(5)(H): Deleting language from this section related to identification of “wells which may require integrity testing or well logging” because all wells are subject to integrity testing.

Response: *NOT ACCEPTED. All wells require integrity testing on a default schedule. However, the operator must still evaluate each well using a risk assessment to determine if more frequent testing may be required to meet the performance standard of the proposed regulations. Operators should be aware that the default testing schedule is not sufficient if available data indicates a need for more frequent testing to ensure integrity of a well is maintained.*

0024-48

1726.4(a)(5)(H): Commenter requests the Division recognize the significant costs to re-enter and re-abandon a well and recommends that re-entry, and re-plugging and abandoning should be based on a risk assessment. Commenter provides a table titled “Anticipated Cost Impact to Re-enter into an Abandoned Well and Re-Abandon” for 13 well sites at a cost per site of \$1,000,000 for a total cost of \$13,000,000. The Division should not have the discretion to require re-entry without risk analysis.

Response: NOT ACCEPTED. A prudent operator will perform risk assessments on plugged and abandoned wells and perform re-entry and re-abandonment when necessary. The Division also may require this when appropriate based on information it has available. The Division maintains an awareness of the cost of such activities and requires them only when necessary to prevent harm to life, health, property, natural resources, or the environment.

0025-19

§1726.4(a)(5)(H): The proposed requirements in this section are not sufficient to ensure that all wells in a gas storage project will be assessed, and if necessary, remediated. Submitted data should also include a complete inventory and integrity analysis of existing wells. This should include all wells—whether active, plugged, abandoned, idled, or dry holes—that penetrate the gas reservoir or the AOR. The assessment must evaluate each existing well and should include a well record review, field inspection and testing, and corrective action including reworking and plugging/re-plugging as needed to protect life, health, property or natural resources.

Response: NOT ACCEPTED. The data required in this section include identification of all wells associated with the project, including all plugged and abandoned wells, and all wells that have penetrated the storage zone; each well must be evaluated for containment assurance and necessary integrity testing and logging must be identified. But this proposed section does not stand alone. Proposed section 1726.3, subdivision (c)(1) also requires that the construction and design of all wells conform to the requirements of these new regulations and provides a schedule for bringing non-conforming wells into compliance. The requirement to demonstrate the integrity of all wells, along with the well construction standards, monitoring and testing requirements, and the risk assessments conducted under the RMP, will be sufficient to ensure that all wells are identified and evaluated with corrective action as needed.

0030-31

§1726.4(a)(5)(J): It is essential to require maps of all “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” regardless of whether it is “publicly available.” These are essential safety considerations and must not be omitted merely because the information is not in the public domain.

Response: NOT ACCEPTED. Where industrial activities do not fall under the jurisdiction of the Division, these regulations cannot require disclosure of proprietary information, and it is unlikely that such specific information would be necessary. As this

requirement is limited to maps of locations and does not require additional detail regarding the operations themselves, it is likely that the majority of information needed will be in the public domain via local permitting or state regulatory agencies.

0012-1

§1726.4(a)(6)(C): The monitoring system for the detection of leaks should be accessible 24 hours a day, 7 days a week and should be made accessible to the public online. The Porter Ranch Community has lost a great deal of trust in the system that should have protected us from the gas leak blowout that occurred on October 23, 2015; taking steps to make the public feel in real time that the facility is allegedly safe will help everyone. DOGGR needs to earn the trust of the community.

Response: *NOT ACCEPTED. The monitoring system for each well is needed to ensure that the operator can detect and respond to leaks, which must be immediately reported to the Division with a response plan (or a notice that it has been fixed). However, it is not necessary for this regulatory purpose that this system be digital or online, which would significantly increase the cost associated with the requirement.*

0024-49

§1726.4(a)(6)(E): More specificity is needed on what type of sourcing information is required when submitting a summary of the source and analysis of gas injected.

Response: *ACCEPTED. The requirement for sourcing information has been deleted. Analysis of the gas is all that must now be submitted to the Division under this proposed section. Where information regarding the source of injectate is needed, the Division will specifically request it from the operator under its discretion to request additional data as needed.*

0026-31

§1726.4(b): Commenter suggests the replacement of this section requiring updated data in case of change in conditions or available accuracy with the following language which is consistent with DOGGR approval letters “The Division shall be notified of any anticipated change in a project resulting in alteration of conditions that were originally approved, such as: increase in size of the project; increase in the approved zone pressure; changes in the injection-withdrawal intervals; changes in the observation-collection intervals; or monitoring procedures. Such changes shall not be carried out without Division approval.”

Response: NOT ACCEPTED. Updated data in case of condition change or more accurate data availability is necessary for effective regulation of the project and is expressly required under PRC section 3181, subdivision (a)(1). The Division maintains a database of information submitted and monitors that data for consistency and validity over time so that potential hazards can be identified with comparative data analysis. Commenter's language would limit the data provided to the Division in ways that would limit the Division's ability to effectively supervise operations and would be inconsistent with the statutory requirement.

0020-9, 0024-7

§1726.4(d): The data requirements of this section should only be applicable to new UGS projects as several of the data requirements would be impractical to obtain for existing storage projects. As written, the regulation uses language in this section such as "proposed" that indicates it is intended only for new wells and projects, but this should be explicitly clarified with new language to specify that existing facilities will not be subject to the project data requirements unless the operator has new data to provide or information has changed.

Response: NOT ACCEPTED. The purpose of the UGS project data requirements is to ensure that project data demonstrates that stored gas will be confined to the approved zone of injection and that the underground gas storage project will not cause damage to life, health, property, the environment, or natural resources. This is necessary for both existing projects and new projects, and is required under PRC section 3181, subdivision (a)(1). Where it may be difficult for operators to provide a specific data type, the proposed regulations allow the operator to propose an alternative to the Division for data that will otherwise meet the performance standards. Language such as "proposed" has been removed to clarify that requirements apply to all projects and all wells within all projects, both new and existing.

0024-50

§1726.4(d): Where data is unavailable, an operator should initiate a program to mitigate the risk from the lack of data rather than giving the Division discretion to accept alternative data. This program should be a part of the RMP.

Response: NOT ACCEPTED. Not all additional data requests are risk based. The Division has a broad duty to protect and broad discretion to provide oversight of gas storage operations. The Division takes a holistic data approach, creating a database of information that can be used in multiple ways to better manage the wise development of oil and gas resources. Where a specific data set may not be available to an operator,

the proposed regulations require that alternative data be provided because the performance standards must still be met. Any needed mitigation measures indicated by the lack of data must also be included in the RMP.

0025-20, 0030-28

§1726.4(d): Commenters note that all of the data required in 1726.4(a) are both essential to ensure well safety and feasible to provide and request that subsection (d) be removed. There should be no reason for DOGGR to accept less, as is permitted by this section. The long history of lax agency supervision and inadequate data reporting by operators is ample evidence that such discretion to accept incomplete data is a recipe for disaster. If gas storage project operators are unable to provide this critical data, such projects should not be approved. Alternatively, this subsection should establish a process of public notice and comment on the proposed alternative data to be accepted.

Response: NOT ACCEPTED. The purpose of the data requirements in this section is to provide a complete file for evidence-based decision making. The specific data types or requirements are less important than the ability to gain a comprehensive picture of the conditions and challenges surrounding the wells and the project. As such, where an operator can demonstrate that an alternative piece of data provides the same information or otherwise informs the scientific analysis, the Division has the flexibility to accept that alternative data. As this is a scientific evaluation of data quality equivalence, it is not an appropriate subject for public comment.

0008-3, 0052-6

§1726.4(f): Public notice of new and amended gas storage projects should be provided and project data made available online.

Response: ACCEPTED IN PART. *UGS project data and approved RMPs will be published on the Division's public website as required by PRC section 3181. A specific Public Notice release, which requires email and mail notice to a large number of persons who have registered to receive notice, is infeasible for regular approval operations. Instead, data will be posted in the well database and on the Division website as it becomes available and has been reviewed for confidentiality. A new UGS project would involve permitting by either the CPUC or the Federal Energy Regulatory Commission, and both of those permitting processes involve extensive environmental review and opportunity for public comment.*

1726.4.1 CASING DIAGRAMS

0010-38

§1726.4.1: Commenters recommend replacement of the phrase “casing diagram” with the phrase “wellbore diagram” in all sections of the proposed regulations.

Response: *NOT ACCEPTED. The use of the term “wellbore” usually includes diagrams of the below ground portion of the well only. The term “casing diagram” is a broader requirement that includes not just the tubular and below ground equipment, but the configuration of the well including master gate valves and other equipment that is emplaced above the surface as part of the integrated casing system. A “wellbore diagram” is insufficient to achieve the purpose of the regulations, as these terms are not interchangeable.*

0025-21

§1726.4.1: Commenters support the proposed requirements for casing diagrams and recommend that the following also be included: date drilled; date idled, if applicable; and date plugged, if applicable.

Response: *ACCEPTED IN PART. Language requiring the date the well was spudded and the date cement plugs were emplaced has been added to the requirements for casing diagrams.*

NOT ACCEPTED. The date idled would not be appropriate for inclusion on a casing diagram as it is not a permanent condition.

0010-37

§1726.4.1(a)(1)(I): Commenters propose additions to the casing diagram to include reporting of features that could compromise “the ability to fully access the wellbore to depth.”

Response: *NOT ACCEPTED. It is not always necessary to access the wellbore to full depth. In some cases, effective depth is sufficient. Items that might interfere with accessing to depth can include fish and junk, which may be left in the hole without creating risk. In addition, the purpose of the proposed casing diagram section is to ensure there is an adequate picture of the reservoir, caprock, wells and potential leak paths. The ability to access the full wellbore to depth is not required for this purpose.*

0027-13

§1726.4.1(a)(5)(F): The regulations expressly state that casing diagrams are not required for shallower wells – only “the same or deeper zone” wells. This leaves out shallow wells intersecting with the Santa Susana Fault lines, which intersect with all of the gas storage wells. This means there is a fast pass system for shallow wells through the fault lines, and the regulations do not require casing diagrams for such wells.

***Response:** NOT ACCEPTED. A shallow well that does not intersect the zone cannot be a conduit for migration unless the zone has already been compromised. By ensuring that all wells which penetrate the zone maintain their integrity via the regulatory requirements, concerns about secondary migration from uncontrolled sources are mitigated. If a confining fault is compromised such that it is serving as a conduit for migration, the reservoir competency has been compromised and additional mitigation actions will be required by the Division using its discretionary authority.*

1726.4.2 RECORDS MANAGEMENT

0010-10

§1726.4.2: Commenters believe DOGGR should include in each well’s file a note articulating what variances have been granted and providing evidence that shows that the variance meets the appropriate standard.

***Response:** The Division’s practice is to make a note or issue a written statement to the operator when significant case-specific determinations or approvals are made, and that note or statement would be included in the well or project file.*

0025-22

§1726.4.2: Commenters support the addition of the proposed requirements for operators to develop a Record Management Plan. Commenter concurs with the Division’s statement in the Initial Statement of Reasons that appropriately managing records is crucial to the safe operation and rigorous oversight of UGS requirements.

***Response:** NOTED. Thank you for your comment.*

0010-8

§1726.4.2(b): Commenters suggest changing the required period for records retention from the lifetime of the project to five years after decommissioning, providing for seamless handoff to subsequent operators or the agency as appropriate. DOGGR should retain all records related to gas storage projects in perpetuity –the information

contained in these records could ultimately be vital to diagnosing and resolving any potential subsurface issues in the future.

Response: *NOT ACCEPTED. The Division has the authority to request documents from the operator that may be required to maintain well and project files sufficient for regulatory purposes. Well records maintained by the operator may contain a large number of records that are not relevant to Division jurisdiction and are not needed to preserve the well history. Where the Division may be concerned about the preservation of records after an UGS project has ceased operation, provisions for record retention may be required as part of a decommissioning plan.*

0024-51

§1726.4.2(b): Commenter suggests the term “all records” is too vague and requests clarification. Commenter suggests replacing “all records” with “those records necessary to establish compliance with.”

Response: *NOT ACCEPTED. The proposed regulation requires a plan for identifying as essential “all records related to evidence of conformity to the requirements of this article,” which is a clear statement of inclusion for any and all documents, data or other records which may contain evidence of compliance with regulatory requirements. “[T]hose records necessary . . .” as recommended by commenter suggests a limited subset inconsistent with regulatory goals for complete records.*

0026-32

§1726.4.2(c): Commenter requests clarification for “The operator shall submit its Records Management Plan to the Division.” Commenter believes in the importance of the operator managing plans impacting the operations of their facilities.

Response: *NOT ACCEPTED. This statement is clear – the plan for records management must be submitted to the Division. The Division will then hold the operator responsible for meeting the minimum regulatory requirements in the manner described by the plan. This does not negate the operator’s responsibility to manage the records management plan as it may impact operations, but provides the Division with the ability to ensure that operators are meeting a minimum regulatory standard without imposing a prescriptive plan. The proposed regulation has been revised and the express requirement for review and approval of the records management plan has been removed, but the plan must still be submitted to the Division.*

0026-33

§1726.4.2(c): Commenter believes the Records Management Plan to be based on the operator's records retention policy that have been established in compliance with applicable regulations and recommends replacing "ensures records are" with "enabling records to be" and requests clarification on "Records may be protected following a graded approach, commensurate with the value of the record and the cost to reproduce the information."

Response: NOT ACCEPTED. Commenter's suggested language "enabling" is a lesser standard than "ensures" and dilutes the requirement of the regulation so that regulatory goals would not be met. Operators must ensure records are available and protected, not just enable them to be so. The Division believes the intent of a graded approach is clear – the records management program may provide that more valuable records and records that would be costly to reproduce, be subject to a higher level of protection than records that may be easily reproduced or contain information of little value to future analysis.

0020-10, 0024-9

§1726.4.2(c) and (d): Commenter recommends streamlining the records management section by removing the specific requirements for filing, storage, and processes. The Records Management Plan submitted to the Division will establish the appropriate processes and procedures for maintenance of the records according to each operator's unique circumstances and aligning with their company-wide strategies.

Response: NOT ACCEPTED. Operators are free to use any plan for records management that meets the specified standards, but the Division does not believe a system without standards would be effective at achieving regulatory goals. Proposed subdivisions (c) and (d) specify a minimum standard for the physical protection that must be established for records and detailed requirements for the tracking system, which are not contained in any other proposed subdivision.

0024-52

§1726.4.2(e): Commenter suggests the term "prompt retrieval" of records is too vague and recommends "within a reasonable timeframe".

Response: NOT ACCEPTED. "Prompt retrieval" includes an urgency element with a need to retrieve and deliver for immediate use. "Within a reasonable timeframe" suggests that it could be done at the operator's convenience, which does not meet the need of the regulatory requirement. Records must be available for prompt retrieval in

circumstances where data or information is needed in an emergency and to facilitate effective records inspections by the Division.

1726.5 WELL CONSTRUCTION REQUIREMENTS

0001-3, 0002-1, 0008-4, 0015-8, 0027-14, 0030-12, 0030-36, 0035-2, 0039-1, 0046-6

§1726.5: Commenters would require surface and subsurface safety valves (SSSV), both automatic and remote-actuated, with an incorporated warning system, for all gas storage wells, not merely depending on the well's distance from populated areas. The SSSV requirement should be mandatory for all injection wells, not limited to "critical" wells, as it is clear that the gas can migrate and affect people and the environment at significant distances beyond the 300-foot limit for critical well designation. One commenter suggests the proper proximity for consideration is five miles from residential properties and zoning. Commenters demand that the issue of valves be addressed in a public forum by both the CPUC and DOGGR, where documentation of the reasoning and decision process not to require these valves must be presented. Commenters are also concerned about DOGGR credibility on this issue. Good design, such as in aerospace passenger aircraft, (and under the auspices of FAA rulemaking), assure that high pressure lines ALWAYS have source shutoff capability in the event of failure. A surface controlled sub-surface safety valve should be installed in the tubing string approximately 50-200 feet below the tubing hanger, with fail shut control lines in the tubing-casing annulus. Commenters indicate that this is a public health and safety issue; leaks and accidents at these facilities can contaminate the environment and affect populations many miles away.

Response: *NOT ACCEPTED. It is the intent of the proposed regulations to set performance standards using risk assessment and hazard analysis, rather than specific prescriptive requirements for well design and construction. As such, proposed section 1726.3(d)(2) requires operators to determine if surface, subsurface, or remote-actuated safety valves are appropriate considering a list of factors including: proximity to other buildings and sensitive areas, gas composition and operational flows, risk assessments and distances to known hazards, age of the well and the risk of sabotage, as well as current and predicted development in surrounding areas, topography, local wind patterns, geologic hazards, and the availability of alternative protection measures. Where an alternative hazard reduction strategy or technology may provide equal or greater protection than a safety valve, the Division would encourage the use of an appropriate alternative. A prescriptive requirement for valves in all wells, regardless of appropriateness or need, would vitiate the risk-based, performance-focused approach that is the goal of these proposed regulations. The standard, as designated by statute,*

is the requirement for no single point of failure, which requires two mechanical barriers but does not dictate otherwise how a well must be configured. For “critical wells,” as defined under existing section 1720, surface fail-close, well shut-in or shut-down devices and subsurface tubing safety valves are already required under existing section 1724.3.

0015-6

§1726.5: Operators must assure that all abandoned wells within the project area be 100% cemented for all annular and open spaces from the bottom of the bore to the well head.

Response: *NOT ACCEPTED. Cementing 100% of a well is not always ideal. Cement is very heavy, and if too much cement is poured in a portion of the well open to the formation, the pressure exerted by the cement can damage the formation. Active wells have cement in the annuli at the required locations in the well. To place additional cement in the annulus, perforations must be created in the casing. This creates additional damage to the casing and can make it difficult to reenter a well if the well needs to be re-abandoned in the future. Under current and proposed requirements, the spaces between cement plugs are not empty, but rather filled with a mud specifically engineered for the reservoir conditions a well may experience after abandonment.*

0020-12, 0024-54

§1726.5: The proposed rule may require the installation of tubing and packer equipment within all wells. While tubing and packer completions can be a useful integrity management tool for certain wells/facilities, installing tubing and packer equipment on **all** storage wells that currently flow through production casing will create performance, safety, operability, and economic burdens, without necessarily reducing risk. The majority of natural gas storage wells in the United States (75% or more) do not include tubing and packer completions, and there is no evidence to suggest that these wells are all unsafe. Installing tubing restricts the flow capacity through a well, which may require drilling of additional wells to meet current injection/withdrawal obligations. As a result, drilling more wells could increase exposure to storage well incidents and/or leakage through the cap rock, without necessarily reducing the likelihood or consequence of an incident at a specific well, and without increasing gas availability/reliability for consumers. Installing tubing and packer completions can also increase the safety risk and reliability impacts of well integrity testing, as this equipment may have to be removed and then reinstalled to accommodate the testing. Adding tubing to a well also adds potential leak points, and this additional downhole equipment can present obstacles when responding to a well incident. There is a litany of tools for demonstrating

the integrity of a well and preventing and mitigating issues that arise with wells that do not have a tubing and packer installed. These include, as just a few examples, temperature, noise and wall thickness testing, and cementing behind the production casing and assuring a good quality cement bond with the adjacent intermediate or surface casing.

0020-11, 0024-5

§1726.5(a) and (b): DOGGR should consider modifying the overly-prescriptive well construction requirements related to multiple mechanical barriers, which contradict the risk-based approach elsewhere in the Proposed Rule. Rather than apply across-the-board “multiple mechanical barriers” to address potential “single points of failure,” operators should be required to apply their risk management processes on a well-specific basis to identify the preventative and mitigative measures necessary. The prescriptive construction requirements proposed by DOGGR limit the efficient use of an operator’s integrity management “toolbox” to effectively respond to its risk assessments and achieve performance standards. DOGGR’s final regulations should encourage operators to select the equipment and processes that most effectively and efficiently mitigate risk. The most effective RMP isn’t one that relies on containment of failures, but one that drives *prevention* of failures in the first place. This is accomplished by rigorous inspection and analytical protocols and supplemented by additional measures for the high-risk wells, as determined by the RMP. The “multiple mechanical barriers” requirement fails to reflect this important operating principle.

Response to 0020-11, 0020-12, 0024-5, 0024-54: NOT ACCEPTED. PRC section 3180, subdivision (d)(2), mandates that the proposed regulations require that all gas storage wells be designed, constructed, and maintained to ensure that a single point of failure does not pose an immediate threat of loss of control of fluids. That standard is included in proposed section 1726.5, but tubing and packer is not necessarily required in all wells. Instead, the proposed regulations provide for tubing and packer as an example of a well configuration that does not have a single point of failure, as required under the statutory standard. Tubing and packer is an example of a clearly effective method to achieve the no single point of failure performance requirement. Commenter’s suggestions of other ways to demonstrate integrity, such as testing or cementing, do not meet the requirement for no single point of failure and thus cannot be substituted for a proper configuration with two mechanical barriers.

0024-55

§1726.5: Commenter provides a table titled “*Anticipated Cost Impact to Meet Construction Standard*” for 105 well sites at \$635,000 per well for a total cost of

\$66,675,000. Commenter requests that the Division recognize that if tubing and packer are required in each well, the ability to withdraw and inject will be reduced by 35%, affecting commenter's reliability to serve gas to customers. Additional wells will be required to offset the loss in volume. Commenter provides a table titled "*Anticipated Cost Impact to Drill Additional Wells to Offset Loss of Production Volume*" for 10 well sites at \$4,200,000 per well for a total cost of \$42,000,000. A table titled "*Anticipated Cost Impact to Plug and Abandon a Well*" provides a unit cost per site of \$800,000.

Response: *ACKNOWLEDGED. The Standardized Regulatory Impact Assessment for this rulemaking action considers the substantial economic impacts associated with the proposed well construction requirements, including the potential costs associated with drilling and constructing new wells. The Division has done its best to achieve its regulatory goals and meet statutory requirements without excessive cost burden.*

0027-15

§1726.5: There should be remedial measures allowing the public to challenge the failure to install required subsurface safety valves.

Response: *NOT ACCEPTED. Evaluation of the scientific data and determination of the appropriate well construction configuration are a scientific and engineering decision not appropriate for public comment, which would create unreasonable delay if required for every well where the proposed construction is effective at meeting the performance standards.*

0030-66

§1726.5: At no point should injection or production take place with only a single barrier to the formation or aquifer.

Response: *ACCEPTED. Consistent with PRC section 3181, subdivision (d)(2), the proposed regulation requires the operator to ensure that for every well that penetrates the gas storage reservoir that a single point of failure does not pose an immediate threat of loss of control of fluids.*

0030-37

§1726.5: All wells should be required to have a functioning and installed leak and fire detection system, integrated with a warning system.

Response: *NOT ACCEPTED. Where a risk assessment for the specific well determines that an installed leak and fire detection system with an integrated warning system is*

appropriate to ensure well integrity and prevent damage to life, health, property and natural resources, the operator may use the system. The Division has provided performance standards for well configuration that may be met by any method that provides for two mechanical barriers and regular integrity verification.

0030-38

§1726.5: All wellheads should include a pressure observation valve on the tubing, the packer, and each annulus of the well.

Response: *NOT ACCEPTED. This would be an accepted well configuration, but is not a required well configuration. Operators must determine the appropriate well configuration to meet the performance standards based on their risk assessments and site-specific hazard evaluation.*

0015-28

§1726.5(a): Commenter recommends defining the terms “anticipated operating conditions,” “integrity concerns” and “identified and addressed” in the context of well construction requirements.

Response: *NOT ACCEPTED. These words and phrases have commonly understood definitions within the context of UGS operations based on their ordinary meaning.*

0025-23

§1726.5(a): The Division’s proposed rules fail to distinguish between new well construction and conversion of existing wells to gas storage wells. This is an important distinction. The rules should specify that the design and construction of existing wells must currently meet or can be reworked to meet the same design standards as new wells, and that, if this cannot be achieved, the existing well must be plugged and abandoned.

Response: *ACCEPTED. The words “gas storage” have been removed from proposed section 1726.3(d)(1) to clarify that all wells are subject to these requirements, not just gas storage wells. Language has also been added to proposed section 1726.5(a) to specify that “every other well that penetrates the gas storage reservoir of the operator’s UGS project” is subject to the well construction requirements. These two additions should be sufficient to make it clear that all wells in an UGS project, new and existing, constructed and converted, are subject to the requirements of these proposed regulations and must be brought into conformance or plugged and abandoned within a specified timeframe.*

0010-11

§1726.5(b): The risk of losing well control is one of the greatest risks associated with California’s gas storage fields. Redundant master gate valves should be the default configuration for each well. Without a redundant wellhead design that allows for the ability to work on a well under pressure, an operator’s ability to rapidly respond to an Aliso Canyon-type incident is quite limited. Currently, most gas storage wells in California cannot be worked on under pressure – instead, operators must first kill the well through the tubing and then disassemble the wellhead and install blowout preventers. Installation of a master gate valve on the production casing would allow for working on the well under pressure, eliminating the risks of the more complicated procedure described above. This recommendation is consistent with recommendations in the “*UGS Regulatory Considerations*” (Interstate Oil and Gas Compact Commission/Ground Water Protection Council, May 2017).

Response: *NOT ACCEPTED. A specific requirement for master gate valves would be overly prescriptive. Instead, the proposed regulations provide performance standards that must be met for well configuration and provide an example of a configuration that would meet the standard. Although a master valve is listed as one way to comply, the proposed regulations require operators to use the result of their risk assessments to choose the well configuration that best meets their needs while providing the required standard of protection. The proposed well configuration must then be approved by the Division after the Division has confirmed that the well design is sufficient.*

0015-5

§1726.5(b): Operators must assure all project wells must include 100% cementation of all annular spaces except for tubing/production casing to limit casing flow to production casing only. In the context of these cementing standards, definitions for “isolation” of zones and reservoir, and “sources” of permeability or porosity should be provided.

Response: *NOT ACCEPTED. Cementing of all annuli of all active wells (other than the casing tubing annuli) would require multiple cement ports or perforations of the production casing. This process would greatly weaken the casing. When cementing annuli, the cement must be lifted from the bottom of the well and up the annulus due to the fluid dynamics of the well. Lifting the cement requires a lot of force and cannot be lifted all the way to surface in very deep wells. Cement ports or additional perforations are used in some wells to cement the shallower annuli just below the protected waters, ensuring good coverage of the protected water zone. Adding additional perforations and cement ports would weaken the integrity of the casing, making 100% cementation*

inappropriate in many well configurations. Terms used consistent with their ordinary and common meaning do not need to be defined.

0015-29

§1726.5(b): Commenter recommends that in the context of well configuration, the regulations define what it means to be “demonstrating” adherence to performance standards and require digital, numerical and independently verified information.

Response: *NOT ACCEPTED. The ordinary meaning of “demonstrating” is consistent with its regulatory use and does not require definition within the proposed regulations. The Division will accept whatever evidence is sufficient to show the existence of primary and secondary mechanical well barriers with histories and casing diagrams that show the ability of the casing to withstand full operating pressure. This may include digital and numerical evidence such as test data. Any evidence with scientific validity will be acceptable.*

0015-30, 0025-24, 0030-35

§1726.5(b): Storage well leaks and disasters often occur under unexpected conditions; wells should be constructed not only to withstand expected conditions but also unexpected conditions. This section recognizes the importance of design to withstand excessive loads for case connections, but this design capacity needs to be extended to all aspects of the storage well. For instance: the primary and secondary barriers are only required to withstand “full operating pressure”; string of casing must only contain “*expected* internal and external pressures and tensile loads”; the production casing must be designed to “accommodate fluids on injection and withdrawal at maximum *expected* pressures”; and cementing operations must use a slurry designed for “*anticipated* wellbore conditions.” In each of these cases, the regulations should require that storage well components be designed to withstand *greater than expected* conditions (e.g., a safety margin of 20%).

Response: *NOT ACCEPTED. Pressure testing and casing wall thickness inspections required under proposed section 1726.6 are conducted at 115% of maximum allowable injection pressure, providing for a safety factor in the testing of well integrity. Industry standards generally require a well to be built to sustain integrity based on reservoir pressure, rather than operating pressure, which is always lesser. Thus, the design process inherently includes a safety factor that does not need to be specified in the proposed regulations.*

0052-11

§1726.5(b): Commenter finds the language “is designed safely to contain” and “sufficient” vague as written in this section. It should be made more specific.

Response: *NOT ACCEPTED. The Division believes these terms are clear in context using their ordinary meaning. The surface casing must have the strength to adequately support the loads associated with future drilling operations and the production casing must have the strength to adequately maintain well integrity. The specific strength requirements needed to meet this standard will depend on the circumstances of the well and its surrounding geology.*

0024-53, 0026-34

§1726.5(b)(1): Commenter believes the term “periodic” is too vague and recommends clarifying what the testing requirements are by aligning with Section 1726.6.

Response: *ACCEPTED. The word “periodic” has been removed from both paragraph of proposed subdivision (b)(1) and direct cross-references have been added to clarify that the testing referenced in this section refers to the testing requirements outlined more specifically in proposed section 1726.6.*

0015-31

§1726.5(b)(1) and (b)(4): Commenter indicates that where the primary mechanical barrier or other well infrastructure element has failed, flowing of gases in the secondary mechanical barrier for more than three days per year must be prohibited.

Response: *NOT ACCEPTED. Flowing of gases without two functional mechanical barriers is strictly prohibited. Where a primary barrier or other infrastructure has failed, the well must be taken out of service and remediated. Flowing of gases in the secondary mechanical barrier when the primary barrier has failed for even one day would be considered a violation of both the statute and the regulatory requirement.*

0010-4

§1726.5(b)(1)(A)(iv): On the use of corrosion-inhibiting fluid in the casing/tubing annulus, commenters note that the proposed regulation’s corrosion protocol is mostly focused on monitoring and mitigation, but is lacking a provision that attempts to reduce the likelihood of corrosion in the first place! There is an extent to which this topic is addressed in the risk management planning process, but commenters urge that the use of corrosion-inhibiting fluid be a default requirement.

Response: NOT ACCEPTED. Appropriate mitigation protocols for corrosion will be determined by the risk assessments as part of the RMP. Corrosion-inhibiting fluid may be an appropriate mitigation measure implemented by some operators, but the proposed regulations require ongoing risk assessments rather than prescribing specific mitigation protocols for every well to allow for flexibility and the use of new techniques and technologies as they are developed.

0015-27

§1726.5(b)(1)(B): Commenter recommends requirement of a Project Operating Plan, including the provision of contents and schedules prior to approval of a project. The Project Operating Plan should describe “normal” operations, which should be defined. The plan should cover all operations including all oil, water, and other material removal and injections within the project area.

Response: NOT ACCEPTED. The detailed requirements suggested by commenters are inconsistent with the performance based requirements that are the backbone of these proposed regulations.

0026-35

§1726.5(b)(1)(B): Commenter suggest the deletion of “annular” from this section. Annular testing cannot be completed as described and could result in mechanical failure of bottom hole equipment.

Response: ACCEPTED. The language has been removed and a direct cross-reference to the testing requirements of proposed section 1726.6 has been added for clarity.

0015-32

§1726.5(b)(2): Commenter recommends definition of the terms “designed” and “safely” in the context of production casing.

Response: NOT ACCEPTED. The Division believes these terms are clear in context using their ordinary meaning. Casing must be designed to safely contain the expected internal and external pressures and tensile loads. The specific strength requirements needed to meet this standard will depend on the circumstances of the well and its surrounding geology.

0030-39

§1726.5(b)(2): The cement casing must be a comprehensive casing design that ensures redundant barriers and must be required from the surface to the base. The

casings should be cemented so that there is sufficient cement filling the annular space outside the casing from the shoe to the surface. Commenter suggests that the regulations specify minimum requirements for overlapping casing strings, such as 200-feet of overlap. As they stand now, they are vague.

Response: *NOT ACCEPTED. Cementing requirements are outlined in existing regulations, section 1722.4, which applies to UGS wells, and do not need to be duplicated in the proposed regulations.*

0015-33

§1726.5(b)(3): Where surface casing standards are set, commenter recommends application of those standards to all casings including conductor, surface and intermediate casings. Commenter also recommends defining “sufficient” in the context of these casing standards.

Response: *NOT ACCEPTED. The casing standards of this proposed section are specifically applicable to the surface casing, which must be able to support the weight of wellhead equipment and drilling rig. Other casings do not have the need to support this load so do not need to meet this requirement. The term “sufficient” is used consistent with its ordinary meaning and does not require additional definition. The casing must have the strength to adequately support the loads associated with future drilling operations.*

0010-12, 0052-12

§1726.5(b)(3) and (4): Commenters recommend requiring that surface casing, and intermediate casing be cemented to the surface, perforations created for investigative or remedial work be sealed with cement and pressure tested, and for production casing to be properly cemented (alternatively, production casings should be cemented to the surface).

Response: *NOT ACCEPTED. UGS projects remain subject to section 1722.4 of existing regulations, which provides cementing requirements including specific requirements for surface and production casing. Cementing and pressure testing of investigative or remedial perforations is required.*

0025-25

§1726.5(b)(6): It is unclear what is meant by the phrase “sources of permeability or porosity.” Storage wells should be cemented to ensure that the reservoir is isolated from

all other potential flow zones, consistent with API Standard 65-Part 2, Isolating Potential Flow Zones during Well Construction.

Response: *ACCEPTED IN PART. Language regarding permeability and porosity has been removed from this proposed section so that the requirement is to cement so as to maintain the integrity of the storage zone by providing isolation of the reservoir from communication of fluids.*

0024-56, 0026-10

§1726.5(b)(6) and (7): The proposed sections require that cementing be performed to surface for surface casing and at least 500 feet above the reservoir for intermediate and production casings; 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 dissolved solids content. Commenter believes these requirements should apply to new wells only. If applied to existing wells, this Section could require perforating production casing thereby having the potential to compromise the secondary barrier.

Response: *ACCEPTED IN PART. The requirement for a cement slurry designed for anticipated wellbore conditions has been removed from proposed subdivision (b)(7) to a new subdivision (b)(8), which will apply to new wells only. The remaining language in proposed subdivision (b)(7) provides a performance standard for cementing without prescribing how or where such cementing must be performed and will apply to new and existing wells.*

NOT ACCEPTED. Proposed subdivision (b)(6) has been modified to remove prescriptive language specifying how isolation of the reservoir must be accomplished. The remaining performance standard must be met by new and existing wells. The requirements of subdivisions (b)(7)(A) and (B) are existing requirements under section 1722.4, and existing wells should already be in compliance. Language has been added to the proposed subdivision (b)(6) to cross-reference the requirements of 1722.4 for clarity. In addition, proposed subdivision (c) allows for alternative constructions where sufficient evidence that the performance standard can be met is provided to and approved by the Division.

0010-15

§1726.5(b)(7)(A): Commenter suggests a proposed revision in the surface casing section requiring remediation if cement fails to return to surface. This is a basic principle that would address one of the concerns around SS_25 – that initial cementing was incomplete due to lost circulation.

0010-16

§1726.5(b)(7)(B): Commenter added a provision requiring that “When intermediate casing is installed to protect groundwater, the operator shall set a full string of new intermediate casing to a minimum depth of at least 100 feet below the base of the deepest strata containing protecting groundwater and cement to the surface.”

0010-17

§1726.5(b)(7)(B): Commenter recommends a provision increasing the required cement height above protected groundwater zones from 100 feet to 500 feet.

Response to comments 0010-15, 0010-16, 0010-17: NOT ACCEPTED. UGS projects remain subject to section 1722.4 of existing regulations, which provides cementing requirements including specific requirements for surface and production casing.

0025-26

§1726.5(b)(7)(B): The 2011 Horsley Witten Group review of California’s UIC program highlighted a number of issues, among them the concern that Underground Sources of Drinking Water (USDWs) containing more than 3,000 milligrams per (mg/L) total dissolved solids (TDS) are not fully protected under the California UIC regulations due to California’s use of the term “fresh water,” which has been used to describe groundwater that contains 3,000 mg/L or less TDS. While commenters recognize that groundwater with 3,000 mg/L or less TDS will typically be shallower than groundwater with 10,000 mg/L or less TDS, this is not necessarily always the case. In addition, groundwater containing 3,000 mg/L or less TDS may not be present at all. In order to ensure that all groundwater that meets the federal definition of the USDW is protected, commenters recommend the addition of “...or groundwater that has 10,000 or less milligrams per liter of total dissolved solids content, whichever is shallower.”

Response: ACCEPTED IN PART. The suggested revision is not necessary as the purpose of the well constructions standards in proposed section 1726.6 is to ensure that wells penetrating the gas storage zone do not act as a conduit for fluids to migrate out of the gas storage zone. The requirements for cementing of casing to protect specific categories of groundwater are contained in existing regulation section 1722.4 and do not need to be duplicated here.

0015-34

§1726.5(b)(10): Commenter recommends defining “adequate” in the context of cement bonds between casing, cement, and bore walls. In the same context, commenter

recommends including a definition for “formations” as compared to “geologic formations,” zones, members, units and bedrock.

Response: *NOT ACCEPTED. The detailed definitions that commenter suggests would add unnecessary complexity. Division staff and operators work together using a basic understanding of terminology that is generally agreed upon across the academic and professional community, based on the ordinary meaning of these terms.*

0025-27

§1726.5(b)(10): The term “cement bond log” refers to outdated technology and the term “cement evaluation log” is preferable. Cement integrity and location must be verified using cement evaluation tools that can detect channeling in 360 degrees. A poor cement job, in which the cement contains air pockets or otherwise does not form a complete bond between the rock and casing or between casing strings, can allow fluids to move behind casing from the reservoir into USDWs. Verifying the integrity of the cement job is crucial to ensure no unintended migration of fluids. Traditional bond logs cannot detect the fine scale channeling which may allow fluids to slowly migrate over years or decades and therefore the use of more advanced cement evaluation tools is crucial and must be required. In addition, cement bond may deteriorate over time, so it is crucial that any cement evaluation log used by the Division to evaluate and verify cement bond be representative of current well conditions. Commenter recommends editing this section to include the preferred term and add requirement that any cement evaluation may be no more than two years old.

Response: *NOT ACCEPTED. The bond log or evaluation required by this proposed section is generated when the cement is placed in the well, regardless of how long ago that cementing may have taken place. Thus, a requirement that the evaluation be less than two years old is not appropriate. Evaluation of cement bond quality after emplacement is covered by mechanical integrity testing requirements (proposed section 1726.6).*

0015-35

§1726.5(b)(11): Commenter indicates that packers set in cemented casing should be located within caprock and upward to the surface. Commenter recommends elimination of language allowing for alternate locations acceptable to the Division.

Response: *NOT ACCEPTED. Proposed subdivision (b)(12) calls for the packer to be set in cemented casing within confining strata (including the caprock) as commenter seems to request. However, subdivision (c) allows for alternative methods of achieving*

the performance standard articulated in subdivision (a), and the option for alternate locations cannot be eliminated. The geology of every location and the configuration of every well is unique. Where necessary to ensure safety or for any other reason determined appropriate by the Division, the location of the packer may be modified to accommodate this uniqueness.

0025-28

§1726.5(b)(12): Ensuring that wellhead components meet appropriate design and operation parameters is crucial to achieving and maintaining mechanical integrity. As such, commenter recommends that the Division adopt standards for wellhead components for gas storage wells, such as those adopted by Kansas (See K.A.R. § 82-3-1003(f)) that include a requirement for components made of steel of sufficient pressure rating to exceed maximum injection pressure with ratings stamped on valves and fittings. It should also require master valves to be fully opening and sized to the diameter of the tubing, with each flow line equipped with a manually operated positive shutoff valves

Response: *NOT ACCEPTED. All equipment must be tested to ensure it meets minimum integrity standards, but the Division does not believe that the prescriptive requirements proposed by commenter are necessary. Risk assessment under the RMP will determine the appropriate well configuration based on performance standards which require zonal isolation and mitigation of hazards. Commenter's specific requirements for the master valves may be appropriate in some situations but not others. Shut off valves would usually be found on the Christmas tree, not the flow lines, and automatic valves with manual bypass are often used.*

0010-45

§1726.5(b)(X-new): Commenter recommends requiring the use of an intermediate casing to protect ground water when surface casing was set above the base of protected groundwater and additional groundwater is found below the surface casing shoe.

Response: *NOT ACCEPTED. Existing regulation section 1722.3 provides specific requirements for use of intermediate casing, and provides the Division the ability to require additional casing if needed. A mandatory requirement for intermediate casing is contrary to the risk-based, site-specific approach of the proposed regulatory scheme.*

0010-18

§1726.5(c): Commenter suggests an adjustment to the variance process. In particular, the bar for variance from the use of tubing and packer should be high, and DOGGR should require considerable evidence from operators seeking such variance that it is necessary and that the alternative well configuration is at least as protective of safety and the environment.

Response: *NOT ACCEPTED. In this case, tubing and packer is just one example of a well configuration that could meet the performance standards. Thus, use of an alternative method is not variance, but simply a proposed method of meeting the regulatory standards. Language in the proposed regulations specifies the performance standard that must be met.*

0025-29, 0030-40

§1726.5(c): This subsection provides the Division with broad discretion to waive the preceding requirements, which are critical to ensuring that wells used in gas storage projects are properly designed and constructed. Commenters recognize that performance-based standards can be effective in achieving environmental and health and safety goals. However, in order to do so, clear, measurable, and enforceable outcomes and expectations must be established. The Division's proposed rules fail to do this. Deviation from the specifications should be allowed only upon the provision of detailed evidence that an alternative design will be as effective or better, and any approval of alternatives should be fully transparent with ample public notice and opportunity for comment.

Response: *ACCEPTED IN PART. Language has been added to clarify the minimum performance standards which must be met for well configuration. Consistent with the statutory mandate of PRC section 3180(d)(2), the new language specifies that construction must include primary and secondary mechanical well barriers to isolate the storage gas.*

NOT ACCEPTED. There are many reasons why well configuration may vary from the examples provided by the regulations. Well design and construction must adapt to geologic variation and site-specific characteristics; there may be circumstances where well construction other than tubing and packer is appropriate. The Division must be flexible if it is to ensure that local conditions are accurately accounted for and such flexibility will provide for better protection than a one-size-fits all standard. Evaluation of the scientific data and determination of the appropriate configuration are a scientific and engineering decision not appropriate for public comment, which would create

unreasonable delay if required for every well where the proposed construction is effective at meeting the performance standards.

0015-36

§1726.5(d): These requirements must apply to all wells used for injection in any manner and thereby for all Underground Injection Plan/Program.

Response: *NOT ACCEPTED. These proposed requirements are intended to specifically apply to wells used in UGS projects. There are other existing regulations, and regulations in development, which will specifically address underground injection activities outside of gas storage projects. The Division has determined that the “one size fits all” regulations, which previously applied to multiple types of oil and gas activities, are no longer appropriate given the complexity and nuance of the different project types.*

0025-30

§1726.5(d): Commenter appreciates the Division’s clarification that these requirements are in addition to all other well construction requirements. As such, it is critical that the Division move as expeditiously as possible to update and revise its other existing well construction requirements, many of which are out-of-date and do not reflect current best practices. Given that the safety of UGS projects is contingent on the stringency of those existing regulations, a rulemaking to update those regulations should be moving in parallel to this rulemaking, to ensure that the Division meets its statutory obligations at PRC section 3180, which mandates that the Division promulgate regulations that establish standards for the design, construction, and maintenance of all gas storage wells to ensure that integrity concerns are identified and addressed before they can become a threat to life, health, property, the climate, or natural resources.

Response: *NOTED. Thank you for your comment. .*

1726.6 MECHANICAL INTEGRITY TESTING

0010-19

§1726.6: Ongoing testing of each gas storage well’s internal and external well integrity is crucial to preventing future Aliso Canyon-type incident

Response: *NOTED. Requirements for ongoing integrity testing are a core component of these proposed regulations.*

0020-13, 0022-3, 0024-3, 0026-8

§1726.6: Commenters agree with the proposal to require integrity testing of all storage wells; but encourage the Division to base integrity testing requirements on risk, consistent with API RP 1171. The specific time intervals proposed increase risk to employees, formation integrity, and service reliability and may have the unintended consequence of damaging the equipment. Operators should be allowed to determine the appropriate frequency for integrity testing for each well based on a risk assessment and subject to Division approval, rather than defining a default timeframe in the regulation. In addition, there could be an impact to the reliability and delivery of natural gas associated with the sheer number of wells undergoing tests at any one time. Due to these potential impacts, the frequency of the testing should be based on an assessment of risks and a history of assessments for each well, instead of prescriptive timeframes.

0020-17

§1726.6: There are important safety and customer impacts of the proposed prescriptive testing frequency. Well equipment, including tubing and packers and subsurface safety valves, may have to be removed to facilitate the required testing. Equipment inside the well casing impedes entry and exit objects, impeding the operator's ability to employ analytical tools (e.g., profile calipers) and run logging/detection programs. Removing tubing, packers, safety valves, and other equipment from all wells at the integrity testing frequency as proposed poses a significant safety risk to employees and runs the risk of damaging equipment. Pressure testing requires filling a well with treated water; filling the well with fluid on a biennial basis risks damaging the storage formation. Some operators currently install new tubing when tubing is pulled, to reduce the risk of thread/collar leak when re-coupling the previously-installed tubing a risk created only by uninstalling and reinstalling existing tubing. Installing the new tubing could cost \$100,000 – \$750,000 per occurrence, varying greatly based on the depth of the well. Furthermore, removal and reinstallation of this equipment adds days to the downtime associated with the proposed testing regime, potentially impacting reliability and availability of gas for customers, especially during peak demand. With over 400 natural gas storage wells in California, the proposed testing frequency has the potential to drastically impact employee safety, gas reliability, and operating cost of natural gas storage wells. By comparison, enhanced recovery and liquid hydrocarbon storage wells subject to federal regulations for the UIC program under the Safe Drinking Water Act, are generally required to demonstrate mechanical integrity every five years.

0022-3

§1726.6(a)(2): There is a very real potential that a blanket default requirement to conduct a casing wall thickness test every two years using narrowly proscribed test

methods may actually increase safety risks at wells with tubing and packer rather than mitigate them. Because tubing generally must be removed to perform the inspection, there is a risk of damage to the casing due to the metal-to-metal contact as the tubing is removed and replaced. The more often tubing must be removed, the greater potential damage to the casing. Additionally, removal of tubing poses a risk of damage to the tubing threads, which could lead to leaks after only one or two tests. Commenters recommend removing the requirement for a casing wall thickness inspection every 24 months and the standard for a Division approved variance.

0022-6

§1726.6(a)(3): Commenter is concerned about pressure testing every 24 months – any safety factor to be gained would be more than offset and overtaken by the safety hazard and damage potential created by unnecessary well workovers. The extraordinary nature of these testing frequencies is made evident when compared with federal regulatory requirements for transmission pipelines, where a hydraulic pressure test is required once prior to placing a pipeline in operation. Under the federal requirements subsequent integrity testing may involve periodic in-line inspections every seven years where the pipeline crosses a high consequence area, but no subsequent pressure testing. Commenters recommend instead a one-time requirement to “verify that the well conforms to the pressure rating specified in the certificate for that well.” Commenter also recommends removing language permitting the Division to approve less frequent testing, and replacing it with language permitting the Division to require additional pressure testing based on risk assessment.

0025-34

§1726.6(a)(3): Part I internal mechanical integrity (the absence of significant leaks in the casing, tubing, or packer), should be demonstrated by requiring owners or operators to continuously monitor injection pressure, rate, injected volumes; pressure on the annulus between tubing and long-string casing; and annulus fluid volume. Commenter recommends the removal of this section and replacement with a requirement for continuous monitoring as required under section 1726.7(d).

Response to comments 0020-13, 0020-17, 0022-3, 0022-6, 0024-3, 0025-34, 0026-8:
ACCEPTED IN PART. PRC section 3180, subdivision (b), requires the Division to specify a mechanical integrity testing regime for gas storage wells that includes regular leak testing, casing wall thickness inspection, pressure testing of the production casing, and other testing deemed necessary by the Division. In consultation with scientists from the National Labs, the Division developed the testing regime laid out in proposed section 1726 based on current scientific understanding of the risk associated with

corrosion in UGS wells. For the pressure testing requirement, proposed section 1726.6(a)(3) provides a default frequency of at least once every two years, but also provides that a different pressure frequency may be established on a well-specific basis based on risk analysis. In response to comment, proposed section 1726.6(a)(3) was revised to make it more clear that the pressure testing frequency should be determined on a well-specific basis as part of the RMP for the UGS project, but that the default two-year testing frequency will apply to any well that does not have an approved well-specific testing frequency.

0020-14

§1726.6: DOGGR should establish performance criteria for baseline mechanical integrity testing. Operators will then conduct baseline testing for each well at a frequency defined in their RMP to establish well condition, if baseline testing has not already been completed for a given well. Companies will then establish reassessment intervals based on risk assessments using the baseline testing data and processes outlined in their RMPs. This process will assure maximum effectiveness of integrity testing with minimum service disruptions by scaling operators' resources and focus based on actual risk to life, health, property, or natural resources.

Response: *ACCEPTED IN PART. The commenters suggestion is consistent with the casing wall thickness inspection and pressure testing requirements of proposed section 1726.6, subdivisions (a)(2) and (3). However, proposed section 1726.6, subdivision (a)(1) requires annual temperature and noise logs for each gas storage well and the proposed regulations does not provide for alternative frequencies for those logs. Temperature and noise logs are cost-effective leak detection tools and the Division does not see a basis for conducting them at least once a year.*

0027-18

§1726.6: This regulation requires mechanical integrity tests and includes provisions for self-reporting by the operator. Self-policing of these injection wells is not safe for the public. In addition, where there is Division discretion to approve test results "with anomalies", the Division has the discretion to modify testing requirements at any time and to excuse operators who do not adhere to the requirements. Provisions should be added to require policing and monitoring by outside agencies in the same manner as when the fire department inspects businesses.

Response: *NOT ACCEPTED. The Division uses its discretion to modify testing requirements when analysis demonstrates it is appropriate and safe. Any alternate testing approved would be reevaluated at each testing, with a return to the original*

testing requirements if test results indicate a need. The Division is charged with ensuring that the testing required under the proposed regulations occurs, and the proposed regulations require operators to provide the Division with an opportunity to witness all mechanical integrity testing

0027-19

§1726.6: The proposed regulation does nothing to restrict injections to wells that can withstand frack pressure. This requirement would ensure there are no injections in wells that have known defects.

Response: *NOT ACCEPTED. Where a well has failed a mechanical integrity test and is known to have issues, it may not be used for injection or withdrawal without approval from the Division. Wells with known defects will require additional testing or mitigation measures if they are to be used for injection, provided that such measures can ensure confinement of fluids to the injection zone. A specific requirement to prohibit injection within wells that cannot withstand frack pressure is not necessary.*

0010-20

§1726.6(a): Commenter calls for an appropriate repeat section (generally 100' to 200' interval) to be run to verify log data accuracy and made a part of the log presentation, unless well conditions warrant otherwise. Logging should be conducted according to industry or Division standards.

Response: *ACCEPTED IN PART. Proposed section 1726.6, subdivision (a)(1) has been revised to require a repeat section to ensure that any anomalous reading is due to a well anomaly and not a tool problem, with a focus on intervals where anomalies are present.*

NOT ACCEPTED. Testing and logs will be done to the minimum accepted standards that will achieve the goals of the testing. The Division will reject any log that does not provide necessary data that is scientifically valid and reliable.

0020-16

§1726.6(a): Commenter notes this this section requires a mechanical integrity test of each well “and every other well that penetrates the gas storage reservoir.” Assuming “every other well” refers to third party wells, storage operators may not have the ability to require an independent third party to allow the storage operator to conduct tests or inspections of their wells. UGS facility operators should be required to collect what data is publicly available if inspection and test data cannot be acquired from the third party. This approach would be consistent with API RP 1171.

Response: *NOT ACCEPTED. Where a third-party well penetrates the storage reservoir, the integrity of that well must be assured. The operator should work with the owner of the third-party well to ensure the required integrity testing takes place. The integrity of orphaned wells that have not been properly abandoned will be the responsibility of the UGS operator until such wells can be properly plugged. Although it may be difficult to secure the cooperation of third-parties and additional cost may be incurred, in order to ensure that the integrity of the storage reservoir is maintained, the integrity of every well must be assured, regardless of ownership.*

0024-58

§1726.6(a): Commenter provides a table titled “*Combined Cost of Biennial Pressure Testing and Wall Thickness Logs (Block Testing to 115%)*” for 49 well sites at a cost of \$1,819,000 per site for a total cost of \$89,131,000. A second table similarly titled provides information on 58 well sites at a cost of \$1,819,000 per site for a total cost of \$105,502,000. Commenter requests that the Division realize that if the biennial testing goes into effect, to offset the volume loss it will require an additional 15 wells be drilled. The provided table “*Anticipated Cost Impact to Drill additional Wells to Offset Loss of Production Volume during Biennial Integrity Testing*” provides for 14 well sites at \$4,200,000 per site for a total cost of \$58,800,000.

Response: *ACKNOWLEDGED. The Standardized Regulatory Impact Assessment for this rulemaking action considers the substantial economic impacts associated with the proposed regulations, including the potential costs associated with drilling and constructing new wells. The Division has done its best to achieve its regulatory goals and meet statutory requirements without excessive cost burden. Under proposed section 1726.6(a)(3) pressure testing frequency will be determined on a well-specific basis as part of the RMP for the UGS facility, and the default two-year pressure testing frequency will only apply where a well-specific frequency has not been approved by the Division.*

0025-31

§1726.6(a): Even wells that do not intersect the intended reservoir(s) or caprock can act as conduits for gas to migrate into groundwater or the atmosphere if gas migrates beyond the vertical and/or lateral confining zone(s) and encounters shallower wells lacking mechanical integrity. As such, mechanical integrity testing should not be limited to only gas storage wells or other wells that penetrate the gas storage reservoir, but rather should be performed on all wells in the gas storage project.

Response: NOT ACCEPTED. A well that does not intersect the storage reservoir can only become a conduit if the confining strata fail or a well in the zone has compromised integrity. All wells that intersect the storage zone will be regularly tested ensuring that migration to shallower wells does not take place. Where confining strata have been compromised, the entire project may need to be re-evaluated and remediation action taken, which can be ordered at the Division's discretion if needed to protect life, health, property, the environment, or natural resources. The Division sees no regulatory purpose to the testing of wells which do not penetrate the storage zone.

0010-22

§1726.6(a)(1): Corrosion is a significant problem associated with well integrity in the UGS fields in California. Commenter would delete this existing regulatory section and replace it with specific and detailed guidance as to how to conduct the test, how to interpret the results, and thresholds for action.

Response: ACCEPTED IN PART. Proposed section 1726.6(a)(2) has been revised to include a requirement to estimate internal and external corrosion and to require the ability to withstand 115% of the well's maximum allowable operating pressure. NOT ACCEPTED. The specific requirements suggested by commenter for how to perform a thickness inspection log are overly prescriptive and do not allow for advancements in testing technologies. The Division always wants to see the method and mathematical calculations used to determine test outcomes, but anticipates that those methods will change. The removal of the preferred "Barlow's equation" and Division discretion to accept other calculating methods, does not meet the Division's need to see the detailed calculations that support an operator's findings and does not provide the Division the discretion it needs to enforce performance standards.

0024-57, 0026-36

§1726.6(a)(1): Commenter believes that not all anomalies from noise or temperature logs are appropriate indicators of threats to mechanical integrity. Thus, not all anomalies should require reporting and such reporting does not need to be immediate. Commenter recommends clarifying language to include anomalies "that indicate a threat to the integrity of the well".

Response: ACCEPTED IN PART. Proposed section 1726.6(a)(1) has been revised to only require immediate reporting of anomalies "that indicate a possible loss of or threat to the mechanical integrity of the well."

NOT ACCEPTED. Immediate reporting of anomalies indicating a possible loss of well integrity is required so the Division can determine what if any response may be needed

to protect life, health, property, natural resources and the environment. Immediate reporting is also necessary to be sure the Division can track the anomaly until such time as it has been explained or resolved. Even if there are no anomalies or only minor anomalies, proposed section 1726.6(d) requires the operator to submit the results to the Division within 30 days so that the Division can maintain a complete history of the mechanical integrity testing of each gas storage well.

0025-32

§1726.6(a)(1): Commenters support the revisions to this section adding a requirement for wells to cease operation when unexplained anomalies exist. It is crucial that the Division require operators to address any mechanical integrity issues that may be identified through testing before those wells are allowed to continue operating.

Response: *NOTED. Thank you for your comment.*

0010-23

§1726.6(a)(2): Because the proposed rule allows casing-only injection under some circumstances, the rule needs to address how to pressure test such wells. Commenters provide language instructing that a mechanical bridge plug shall be set and the pressure test performed on the entire string of production casing when injection is through the production casing only.

Response: *NOT ACCEPTED. Commenter's specific instructions are too prescriptive and do not allow for advances in technology. Any test data that is insufficient to meet the requirements for scientific validity or tests that were performed using questionable methods would be rejected by the Division. The performance standards for the testing allow the operator to choose those testing methods that will best meet the goals of the test without dictating specific methods or configurations.*

0025-33

§1726.6(a)(2): If casing inspection reveals that significant corrosion may be occurring, the Division should require such wells to undergo more frequent and enhanced corrosion monitoring, in addition to actions to remediate corrosion. The Division's proposal to allow a less frequent corrosion inspection schedule lacks sufficient detail or guidance on acceptable methods for determining a corrosion rate and assessing any changes in the rate over time that may necessitate a change in the inspection frequency. Commenter adds language to require a thickness inspection "as part of any well rework where the tubing is removed" and to require a corrosion monitoring program when significant corrosion is possibly occurring. The corrosion monitoring program must

include “monitoring of the well materials for loss of mass, thickness, cracking, pitting, and other signs of corrosion, which must be performed on a quarterly basis.” Such monitoring should include analyzing coupons of the well construction materials, routing the injective through a loop, or an alternative method approved by the Division. Language from this section permitting the Division to approve a less frequent casing wall thickness inspection is recommended for deletion.

Response: *NOT ACCEPTED. The gas transported within a gas storage project is already treated, pipeline quality gas with known lower corrosion rates, making more frequent testing inappropriate. As required by the RMP, corrosion mitigation measures must be identified as part of the corrosion risk assessment and response. The Division does not specify standards for a less frequent casing thickness inspection schedule, because the Division will accept any method that meets the performance standard and wishes to leave open the technologies and methods that may be used to make that demonstration. Monitoring using a real-time data system will be required for all operators by 2020, and the Division always has the discretion to require additional testing or mitigation measures as needed to prevent harm to life, health, property, natural resources, or the environment.*

0026-37

§1726.6(a)(2): Commenter suggests removal of “employing such methods as magnetic flux and ultrasonic technologies” and replacement with “as approved by the Division.”

Response: *NOT ACCEPTED. The language proposed for removal is provided as examples of the methods that may be used to perform a casing wall thickness inspection. The specific methods used to test mechanical integrity will be approved by the Division as part of the RMP.*

0030-41

§1726.6(a)(2) and (3): Mechanical integrity testing should occur annually: the two-year intervals allowed in this section are simply too long. Annual testing is reasonable and essential to protect public health and welfare. MIT testing should also take place after any well has been reworked.

Response: *ACCEPTED IN PART. A reworked well is immediately subject to the integrity testing requirements under proposed section 1726.6(b), but these requirements may be waived if the operator can demonstrate that a specific test is unnecessary due to the nature of the rework.*

NOT ACCEPTED. The two-year mechanical integrity testing schedule was developed in consultation with scientists from the National Labs, based on known averages of corrosion rates in wellbores, and is consistent with industry best practices. Pressure testing presents its own risks and testing more frequently than is necessary would increase the overall risk profile of a given well. Proposed section 1726.6(a)(3) provides for well-specific pressure testing frequencies to be determined as part of the RMP for the UGS facility.

0030-42

§1726.6(a)(2) and (3): Corrosion testing should not be allowed to slip to longer intervals, regardless of observed corrosion rates. Allowing a longer interval upon a finding of little corrosion will provide a perverse incentive to operators to underreport corrosion.

Response: *NOT ACCEPTED. The regulations require operators to base their actions and activities on risk assessments as required for the RMP. Testing is not risk-free; many tests require taking apart the well and risk potential damage as the well is reconfigured for the test, as the test is performed, and when the well is put back together. Thus, the proposed regulations provide a default schedule for mechanical integrity testing, but recognize that the default may be inappropriate in cases where there is little or no corrosion, or where there is corrosion in excess of expectations. Where an alternative to the default schedule is sought by the operator, a simple report of “little corrosion” will be insufficient to justify a less frequent schedule. Instead, operators must provide scientific evidence supporting the lack of corrosion and evidence that such limited corrosion is likely to continue due to field conditions or operational realities. Where there is greater than expected corrosion, the risk management analysis may require more frequent testing. In either case, any exceptions to the default requirements for integrity testing will be based on quantitative risk assessment supported by scientific data, not blind acceptance of reported corrosion rates.*

0010-24

§1726.6(a)(3): Commenter provides a recommendation for the circumstance when, with respect to the pressure testing requirement, the Division allows for a lower testing pressure to ensure that the testing does not compromise the mechanical integrity of the well. Provided that the test at the lower pressure successfully demonstrates mechanical integrity, the Division should reduce accordingly the maximum operational pressure of the well. If a well cannot withstand being tested at the existing maximum operating pressure, it should not be permitted to operate at that pressure.

Response: *NOT ACCEPTED. The storage reservoir has a minimum injection pressure which is required to successfully inject into the reservoir. Where a well has demonstrated its inability to withstand this minimum injection pressure, it will be removed from use and remediated. Well-by-well operating pressures limits are adjusted by Division and operator staff as a part of ongoing well evaluation and risk assessment, and in response to testing results.*

0020-15, 0024-59

§1726.6(a)(3): This section requires a pressure test of at least as high as 115 percent of the maximum operating pressure. Periodic pressure tests at these elevated pressures expand the casing, potentially breaking down the bond between the cement and the casing, especially at the proposed frequency. Pressure testing above the maximum operating pressure for wells will require block testing, which involves taking apart the well. Block testing is intrusive, labor intensive and increases risk to personnel. Allowance must be made so that the pressure on the tubular and packer at the base of the well does not exceed the design pressure; 115% of MAOP at the surface represents a much higher pressure at the bottom of the well. Instead, commenters recommend that the final rule require casing testing and commissioning to follow the recommended practices in API RP 1171, Section 6.9.1, “to demonstrate mechanical integrity and suitability for the designed operating conditions.”

Response: *NOT ACCEPTED. Pressure testing is a requirement specifically identified in PRC section 3180, subdivision (b)(3). A general requirement to demonstrate mechanical integrity is insufficient to meet this statutory standard. The Division is unaware of any method of testing that would achieve the standard without block testing, but the Division will consider any technology proposed by operators that is supported by valid and reliable evidence.*

0022-5

§1726.6(a)(3): Pressure testing to 115 percent of maximum operating pressure at surface would cause the bottom of the well to be tested at excessive and potentially hazardous pressures. It is recommended that the testing pressure be designed to impose 115 percent of maximum operating pressure at the depth of the packer rather than at the surface.

Response: *ACCEPTED. Proposed section 1726.6(a)(3) has been revised and the pressure testing parameters require that the test shall be conducted at least as high as*

115 percent of the maximum allowable injection pressure at the wellhead instead of maximum operating pressure.

0024-60

§1726.6(a)(3): Commenters recommend removing the requirements for the final five minutes of pressure testing as inconsistent with the Division's Order 1109 which was issued to Southern California Gas Company on March 14, 2016.

Response: *ACCEPTED IN PART. Proposed section 1726.6(a)(3) has been revised and the pressure testing parameters require a one-hour pressure test no more than a 10 percent decline from the initial test pressure in the first 30 minutes, and no more than a 2 percent decline from the pressure after the first 30 minutes in the second 30 minutes. These parameters were developed in consultation with scientists from the National Labs and are informed by the Division's experience evaluating pressure tests results as part of the comprehensive safety review at the Aliso Canyon UGS facility. .*

0010-21, 0030-69

§1726.6(b): Integrity testing should be conducted prior to placing any well in service. Alternatively, it should occur prior to commencement of injection or withdrawal operations.

Response: *ACCEPTED. Language changed to specify testing "prior to use," which would include injection or withdrawal operations.*

0025-35

§1726.6(b): Commenters recommend that the Division commit to witnessing a minimum of 25% of all mechanical integrity tests.

0030-43

§1726.6(d): Commenter notes that this section requires notice so that DOGGR staff "may have an opportunity to witness testing." This is insufficient; the regulations should require (make mandatory) that DOGGR staff be present and witness, at a minimum, all annual pressure tests, or alternatively all integrity testing.

Response to 0025-35, 0030-43: *NOT ACCEPTED. It is not necessary to specify in the proposed regulations the percentage of mechanical integrity tests that the Division will witness.*

0026-39

§1726.6(b): Testing of reworked wells should be based on the type of work that was performed during the rework. Any additional testing required should be determined by the supervisor.

***Response:** ACCEPTED. Language has been added to allow for waiver of testing requirements by the Division based on the nature of the work performed.*

0010-25

§1726.6(d): Commenters suggest an edit that would allow DOGGR the opportunity to approve testing procedures, beyond mere notification that certain tests are occurring. It is critical that tests be run properly and with the correct purpose in order to yield useful results, and this provision would put operators on notice that DOGGR is actively reviewing testing procedures to ensure useful outcomes.

***Response:** NOT ACCEPTED. A specific requirement for “approval” is not needed in this proposed section. The Division approves the RMP, which specifies the schedule and method proposed for testing as well as the planned response when testing reveals issues of concern. As testing occurs, each result is forwarded to the Division, which has the opportunity to reject the test as being insufficient in meeting regulatory requirements and the authority to order additional tests if needed.*

0030-44

§1726.6(d): The regulations should require that all inspection and testing records that are submitted to DOGGR be made publicly available as soon as possible thereafter, but in no case more than thirty days after the inspection or testing has been completed.

***Response:** NOT ACCEPTED. Testing and inspection records will be part of the UGS project data that is made available on the Division’s public website, as required under PRC section 3187. It is not necessary to include a timeframe for the Division’s posting of records in the proposed regulations.*

0025-36

§1726.6(e-new): Commenter recommends that the Division specify what actions must be taken in case of a failed mechanical integrity test by adding a requirement to isolate the leak or leaks and demonstrate that the well does not pose a hazard. Within 30 days the operator shall repair and retest the well to demonstrate integrity, or plug it.

Response: NOT ACCEPTED. There can be many reasons for a failed mechanical integrity test, which may or may not include an actual leak. When a well fails a test, the operator is required to notify the Division, and injection and withdrawal must cease until the well has been remediated to the Division's satisfaction. As the reasons for a failed test are broad, the universe of potential remediation actions is even broader. It would be impossible to list all of the possible circumstances and potential responses in regulatory text. In addition, thirty days is insufficient time to respond to many integrity failures, which may involve ordering of parts and/or contracting for a rig. The Division has at all times the discretion to require the operator to perform additional testing, add additional remedial measures, shut-in the well, or require it to be plugged, and this discretion will be exercised on a case-by-case basis depending on the circumstances of the test failure.

0010-26

§1726.6.2(new): Commenter recently commented on DOGGR's UIC program discussion draft, which provides detailed requirements for the various tests that can satisfy a showing of external mechanical integrity. Commenter would import those requirements here, along with key additions necessary for the effectiveness of the tests. Specifically, commenter would require additional integrity testing to demonstrate there is no fluid migration, written approval of testing methods, annual and responsive testing of injection wells, include detailed requirements for temperature surveys and noise logs, cement evaluation logs, and require immediate action to investigate anomalies.

Response: NOT ACCEPTED. The general testing and log requirements commenter includes are already included in the proposed section 1726.6. The level of detail and specific procedure requirements included by commenter are too prescriptive and do not provide the flexibility needed to adapt to changes and advancements in technology. Integrity testing which does not meet the Division's need for scientific validity or procedural integrity will be rejected.

1726.7 MONITORING REQUIREMENTS

0015-42

§1726.7: Commenter believes that the monitoring section contains a number of terms which need to be defined in context including: "inventory," "liquid" vs "fluid," "observation" (differentiate from other project well designations), "seasonally" vs maximum/high and minimum/low inventories, "vicinity" (provide measurements), "spill point," "geophysical logging" (differentiate from geophysical monitoring/seismicity), "offset," "unexplained," "disposal" vs "injection," "intended," "as needed," "immediately,"

“surface,” “cellar,” “minimum,” “real-time” and “zones” (as they relate to the “reservoir” and to “project”).

Response: *NOT ACCEPTED. The extensive definitions that commenter suggests are not necessary. Division staff and operators work together using a basic understanding of scientific terminology that is generally agreed upon across the academic and professional community, and which would be impractical to effectively codify in regulation.*

0018-7, 0030-46

§1726.7: The regulations do not address background monitoring requirements. Natural gas storage projects should be required to continuous monitoring for ambient air levels of potential pollutants of concern, including but not limited to, criteria pollutants, methane, VOCs including BTEX (benzene, toluene, ethylbenzene and xylenes), metals, hydrogen sulfide, and polycyclic aromatic hydrocarbons. Without pre-emergency event ambient data, there is limited ability to interpret monitoring results collected during an emergency event. It is also essential that the public have access to these data.

Response: *NOT ACCEPTED. These issues are within the scope of the California Air Resources Board’s recently completed Oil and Gas Regulation rulemaking.*

0027-4

§1726.7: DOGGR should require tests for chemicals of great concern to the community including: all of the chemicals in the natural gas injected; all of the chemicals in the odorants injected; all of the chemicals in the reservoir and formation fluids; benzene; ethyl-benzene; nitrates and other contaminants from drilling muds; thorium; ammonium; iodide; bromide; hydrogen sulfide; and sulfur dioxide. Testing to confirm the presence of these chemicals should be performed annually or as needed if there are changes in the gases injected.

Response: *NOT ACCEPTED. The natural gas injected into a gas storage reservoir is high quality, processed, commercial gas from producers both inside and outside of the state. Its contents and chemical make-up are generally known as it has been “cleaned,” odorized, and processed prior to transport under federal law. Where there may be small amounts of other chemicals residual in the reservoir, the Division is focused on containment through appropriate well configuration and ongoing integrity verification and does not have a specific use for chemical analysis.*

0030-47

§1726.7: Monitoring of groundwater in nearby aquifers should be also required in order to verify that isolation is achieved. The groundwater monitoring criteria developed for well stimulation projects should be examined for applicability to injection projects. Many of the model criteria for groundwater monitoring near well stimulation projects are applicable to injection projects. The United States Geologic Survey (USGS), in a paper commissioned by the State Water Resources Control Board, asserts that the impacts of well stimulation on groundwater may be indistinguishable from enhanced recovery (i.e. Class II wells), as the same contamination pathways, and similar chemicals may be present. Monitoring groundwater for impacts from underground injection wells would be consistent with the State's current program of monitoring groundwater for impacts from well stimulation. One transferable aspect of the well stimulation monitoring program is the regional groundwater monitoring programs being developed for oil fields where stimulation occurs. These plans should also be developed for any fields where underground injection occurs. Well by well monitoring should also be considered, especially in cases where injection wells penetrate, or are adjacent to, aquifers with beneficial uses.

Response: *NOT ACCEPTED. Although groundwater monitoring is a possible tool for responding to indication of a lack of fluid confinement, the additional benefits of adding groundwater monitoring as a categorical requirement for all UGS facilities are not clear.*

0046-3

§1726.7: Commenter indicates that it is known that gas is coming out of the soil near gas storage facilities. Therefore, some kind of monitoring or prevention system should be required. As it is unlikely that this gas migration is safe, it seems sufficient cause for closure.

Response: *NOT ACCEPTED. The Division is unaware of any specific instance where natural gas from an existing storage reservoir is seeping to the surface. Where this is the case, it should be immediately reported to the Division for identification and remediation. If testing confirms the gas is seeping from the storage reservoir, the Division will take action to mitigate the seepage, including, if appropriate, requiring that wells near the seepage cease injection, as well as any other actions which may be needed to identify the pathway of gas migration and seal it. Shut-in of wells may be required if needed to mitigate or remediate a seepage, and the discovery of a seepage outside project boundaries would be an indicator of a problem with the confining strata requiring Division investigation. A blanket requirement for monitoring beyond the wells and well infrastructure, however, is unnecessary where there is no indication of a seep.*

0010-34

§1726.7(a): Commenter appreciates DOGGR's addition of requiring monitoring of *all* annuli (even those cemented to surface), and not just the production casing/tubing annulus. This small, inexpensive addition is well worth the reduction in risk attained by this broadened monitoring requirement.

Response: *NOTED. Thank you for your comment.*

0015-13, 0052-4

§1726.7(a): Monitoring to detect surface and abandoned well leaks and near-surface field gas migration should be conducted on a daily-weekly basis, especially in light of the Aliso Canyon disaster. This should be one of the performance indicators.

Response: *ACCEPTED. The proposed regulations require daily inspection employing effective gas leak detection technology, with immediate reporting of all leaks to the Division. However, this requirement will no longer apply once the California Air Resources Board has fully implemented its equivalent requirement.*

0015-41

§1726.7(a) and (d): Where a real-time data gathering system is required, commenter recommends that the system be required to be digital and online.

Response: *NOT ACCEPTED. It is likely that the technology used by the operators to meet this requirement will be digital and online. However, the data from this system is not required to be submitted to the Division but is monitored by the operator to inform its activities. Where specific data must be submitted in an electronic format, the proposed regulations so specify. Thus, the Division has no regulatory need for the real-time data system to be digital and online and has no statutory mandate to require it.*

0010-28

§1726.7(b): Commenter suggests adding a requirement in this section that operators submit a plan articulating which monitoring protocols will be used and requiring that observation wells be among them.

Response: *NOT ACCEPTED. The RMP's will specify the plan for integrity monitoring and the protocols that will be used. Observation wells are one of the possible methods that may be appropriate, but they do not need to be required. Other methods, such as semi-annual field shut-in tests, monitoring offset hydrocarbon production or disposal*

operations, and subsurface correlation and gas identification logs can also be used. New technologies may also be developed. It is the goal of the regulations to provide the flexibility to use the methods that will best provide for hazard prevention and mitigation. The Division will work with the operator to approve a RMP that will meet site-specific needs for monitoring and response.

0015-44

§1726.7(b): Commenter suggests that key pressure set points for this section should be set at 10 psi, not 100 psi as proposed. This reduced pressure should be used as the alarm set point for the real-time data gathering system and the trigger pressure requiring additional action by the operator. Where equilibrium pressure is used as a measure, alarm set points shall be no greater than equilibrium plus 10 psi, and when equilibrium plus 10 psi puts casing integrity at risk, action must be taken to mitigate.

Response: *NOT ACCEPTED. The purpose of an alarm set point is to decrease the frequency of response to “false positives” or insignificant fluctuations caused by explainable variations in pressure, such as temperature changes and biogenic gas, unrelated to integrity concerns or gas migration. An alarm set point of 10 psi would create large numbers of false positives. The 100-psi set point is appropriate to identify a build-up of gas in unpressurized casings caused by shallow gas or other fluid migration consistent with the concern of this section.*

0015-43

§1726.7(b)(3): For the purpose of monitoring offset hydrocarbon production or disposal operations, commenter recommends that the regulations define whether there are reservoirs other than for “storage” and provide measurement of “laterally” 500-1000ft or through the project, whichever greater.

Response: *NOT ACCEPTED. The Division sees no value in including a definition for reservoirs other than for storage in this context. If a geologic formation not being used for storage lies within the AOR of the project it would be included in this monitoring requirement. Laterally offset cannot be defined numerically as it would risk excluding activities that are affected by the project and should be included in the required monitoring. The RMP will determine the appropriate inclusion of laterally offset activities based on risk assessment.*

0010-29

§1726.7(c): Commenters recommend a shortened period of 24 hours, by which operators must chemically fingerprint gas from surface or cellar gas releases – time is of the essence in these situations.

***Response:** NOT ACCEPTED. The chemical makeup of a gas release is generally known – those chemicals which are used or injected and present in the reservoir have been previously measured by the manufacturer, supplier, and operator and the injected gas is a treated, pipeline quality gas of known makeup. For these reasons, the proposed regulations have been modified to require a chemical fingerprint only if requested by the Division, with results to be provided as soon as they are available.*

0018-4

§1726.7(c): In addition to the required chemical fingerprinting in the event of a release, UGS facilities should be required to conduct facility specific chemical fingerprints as part of normal operations.

0018-6

§1726.7(c): In the case of a leak or other upset event, an emergency environmental monitoring plan must be implemented immediately and sample for all potential pollutants of health concern, such as benzene, toluene, hydrogen sulfide, etc. Environmental monitoring must be informed by the source gas chemical fingerprinting and kill fluid analysis.

***Response:** NOT ACCEPTED. The gas injected into an UGS reservoir is fully processed, commercial grade gas and the chemical contents are known. Chemicals used onsite are covered by OSHA and Cal-OSHA safety requirements and are supported by Material Safety Data Sheets. The Division sees no regulatory need for additional chemical analysis during operations.*

0022-10

§1726.7(c): Commenters recommend that this section be modified to address the fact that several California UGS projects are located in rural areas with agricultural activity. It is neither practical nor reasonable to require operators of projects in such areas to sample methane releases from agricultural crop production or animal feed operations that may be in the AOR.

Response: ACCEPTED IN PART. Language has been added to clarify that the release should be an unintended release and that the chemical fingerprint will not be required if the operator can prove the gas does not come from the gas storage project or its wells. NOT ACCEPTED. An operator will still be required to demonstrate that any gas detected is not from the project or its wells unless an alternate source can be proved. One method of doing this would be to establish a baseline of methane for the area prior to project operations identifying specific source location and average concentration from non-project uses. This baseline could then be used to demonstrate that a detected release was consistent with non-project activity. Any method that effectively demonstrated the release was not related to the project would be acceptable.

022-11, 0026-41

§1726.7(c): Commenters are concerned that this section could be construed as requiring chemical analysis of any leaks identified on above-ground piping components that are certain to be leaking pipeline quality natural gas, when it is more appropriate to focus on leak repair over gas analysis. Commenters recommend adding language to this section to limit chemical analysis to situations where “a gas sample of sufficient volume for chemical analysis may be feasibly collected.”

Response: ACCEPTED IN PART. Language in this proposed section has been changed so that a requirement for chemical fingerprinting of a gas release may be imposed by the Division rather than as a default requirement. Any and all unintended releases must still be reported to the Division, and the Division will determine when chemical fingerprinting is needed.

0024-62

§1726.7(c): Commenter recommends removing the 48-hour timeframe for chemically fingerprinting gas from a release. Commenter relies on a 3rd party vendor to provide fingerprinting analysis and cannot control their availability.

Response: ACCEPTED. The language has been modified to indicate that the Division may require an operator to chemically fingerprint a release and provide the results to the Division as soon as they are available, but this is no longer automatically required for every release. A timeframe is not specified in the proposed regulations, so that a reasonable response time can be determined by the Division in consultation with the operator based on the circumstances of the release and level of hazard associated with the release.

0027-24

§1726.7(c): The regulations require disclosure but not public disclosure of gas analysis following a release. In addition, the operator can still claim “trade secret” protection on the chemicals and volume on what was released.

Response: *Records of incidents would part of the UGS project data that is made available on the Division’s public website, as required under PRC section 3187. The Division would evaluate validity of a claim of trade secrecy for such data, if such a claim were to be made.*

0026-40

§1726.7(c)-(f): Reporting requirements in section 1726.7 should be as outlined in section 1726.9. Well Leak Reporting.

Response: *NOT ACCEPTED. Proposed section 1726.9 specifically outlines the requirements for reporting of a well leak under PRC sections 3183 and 3183. Proposed section 1726.7 addresses broader requirements for monitoring UGS facilities for any indication of a leak. These monitoring requirements are designed to ensure the Division has current information, which can be evaluated for patterns of concern related to well integrity. Leak reporting required under proposed section 1726.9 is for the purpose of ensuring appropriate response to an actual, significant well leak.*

0030-67

§1726.7(d): Continuous data recording systems must be tested regularly, but no less often than every six months and, if found to be defective, must be replaced as soon as possible but in no case later than thirty days. The leak detection systems and subsurface safety valve systems should be required to be tested at least twice each year, and if defective, replaced within ten days. The twice-yearly test for the SSSV should include activating the actuation devices and a check of the warning system. The operator should test the valve closure at least twice per month.

Response: *ACCEPTED IN PART. Proposed section 1726.8(a) includes testing frequencies and procedures for valves with reference to industry best practices as developed by the American Petroleum Institute. Proposed section 1726.8(b) requires that the master valve and wellhead pipeline isolation valve require annual testing. More frequent testing will be required if justified by risk assessment under the RMP. Ten days is insufficient time for repair of these valves. The regulations allow for 90 days based on the availability of rigs and parts and the Division may always shut-in a well if needed to protect public health and safety. Specific testing requirements for data recording*

systems are not needed, as those systems come with manufacturer testing schedules and warning alert systems to identify when such systems may have operating problems. Risks of system failure will be assessed and mitigated as appropriate within the requirements of the RMP.

0025-37

§1726.7(d): Idle and temporarily abandoned wells threaten the environment and human health and safety and are potential pathways for stored fluids to migrate out of the approved reservoir. Commenter recommends that the Division add requirements specific to idle wells, consistent with best practices used in other states, to ensure that they are properly managed.

Response: *NOT ACCEPTED. UGS wells are subject to the idle well management requirements of PRC section 3206 and the idle well testing requirements in existing regulations.*

0030-45

§1726.7(d): Commenter strongly supports DOGGR's requirement for continuous monitoring of conditions at gas storage wells. A phase-in time of January 1, 2020 is far too long, however. It is feasible for operators to equip their facilities sooner than early 2020. There is simply too great a risk of a repeat of the Aliso Canyon disaster. Continuous monitoring must be implemented on a much shorter time scale. Operators should be required to equip all wells with a continuous, real-time monitoring system with integrated warning systems (CEMS) in order to monitor for the presence of annular gas and fire and leak detection on all wells and data must be made publicly available online immediately.

Response: *NOT ACCEPTED. Many operators use continuous monitoring systems and are already in compliance with the proposed regulatory requirement. As these regulations are unlikely to become effective until late 2018 or early 2019, a timeframe of approximately one year is a reasonable compliance period. All operators are required to perform daily leak surveys, which will temporarily provide sufficient leak detection until the real-time monitoring systems can be installed. Monitoring data submitted to the Division will be made available to the public through the Division's website, after a reasonable period for review, unless determined to be confidential.*

0022-12

§1726.7(d)(3): Commenter recommends that this section be modified to specify that the prescribed measures apply to casing strings without any anticipated surface pressure,

such as surface or intermediate casings, and not to the annuli between production casing and tubing. The measures listed in this section are clearly aimed at distinguishing between migration of shallow gas versus storage gas behind casing and would not be applicable to the annuli between production casing and tubing.

Response: *ACCEPTED. Language was added to this proposed section to clarify that the requirement only applies to strings without anticipated surface pressure.*

0024-63

§1726.7(d)(3): Commenter notes that the appropriate trigger for the actions required under this section is whether the pressure is caused by shallow gas or other fluid migration, irrespective of what the sustained pressure is. The specified pressure limit of “above 100 psi” should be deleted.

Response: *NOT ACCEPTED. This section of the proposed regulations is designed as a process for demonstrating and evaluating casing integrity using pressure, with an upper limit to trigger a requirement for additional testing. 100 psi is a maximum alarm set point to be that trigger. Where operators believe pressure is caused by shallow gas or other fluid migration below 100 psi, a responsible operator would certainly take action even though the alarm set point has not been reached. When the alarm set point has been reached, the operator may demonstrate that it was not caused by shallow gas or other fluid migration, or must take remedial action.*

0024-64

§1726.7(d)(3): The term “equilibrium pressure” is unclear. Commenter recommends using “historically observed pressure” instead.

Response: *ACCEPTED IN PART. The language in this proposed section has been changed to refer to alarm set points based on annular fluid, the initial pressure when the packer was set, and operational configuration. Reference to “equilibrium pressure” has been removed.*

0015-45

§1726.7(e): The Neutron Gamma Ray or equivalent gas detection log should be required on each project well quarterly rather than annually. Required comparisons of results shall also be quarterly rather than year-to-year.

Response: *NOT ACCEPTED. Based on input from other commenters, a gas detection log is now required immediately as a baseline, with the schedule for subsequent testing*

based on the initial test results and risk assessment. Comparisons are required when subsequent tests are performed, but a specific schedule for quarterly or annual testing is no longer required.

0015-46

§1726.7(e): Where the required comparison of periodic gas detection logs shows ANY gas accumulations (not just increasing accumulations) behind the casing, commenter recommends requiring the operator to submit detailed root-cause analyses with their remediation plan.

Response: *NOT ACCEPTED. A baseline gas accumulation is not actual evidence of a leak. This could be an ambient accumulation of natural gas present in the subsurface above a former oil and gas production field, unrelated to the present gas storage operations, thus “any” gas accumulations are not the proper trigger for this requirement. A root-cause analysis is a complex and detailed process that is not appropriate in every situation. Small leaks can be easily detected and remediated without the need for formal causal analysis.*

0022-7

§1726.7(e): The Neutron Gamma Ray or equivalent gas detection log requirement should have been included subordinate to (d)(3)(E) as “further testing,” to be required “only if the pathway of migration is determined to be behind the last cemented casing string,” rather than as a stand-alone subdivision. Commenter recommends renumbering this section and including their proposed language specifying when the requirement is triggered.

Response: *NOT ACCEPTED. Based on recommendations from other commenters, the requirement for a gas detection log remains an independent requirement that has been modified to require a baseline and then subsequent logs for comparison based on risk assessment. The baseline requirement must be met by all operators with further testing as indicated by the test results.*

0024-65

§1726.7(e): Commenter’s current (and recommended) practice is to conduct a baseline Neutron Gamma Ray and then, based on the timing for a well’s casing integrity assessment, a subsequent equivalent gas detection log may be conducted or when other assessments indicate a need. Further, running the Neutron Gamma Ray on an annual basis increases the risk of losing a nuclear type device in a wellbore, particularly if such tools need to be run through downhole safety valves. Commenter provides a

table of costs titled “*Anticipated Cost to conduct NRG*” for 117 well sites at a cost of \$8,200 per site for a total cost of \$943,000.

Response: *ACCEPTED. Language provided by commenter was added to this proposed section providing for a baseline gas detection log with future testing based on risk assessment.*

0025-38

§1726.7(e): Commenters request that the Division clarify what is meant by the term “Neutron Gamma Ray.” It appears this may refer to pulsed neutron logging but clarification is necessary.

Response: *ACCEPTED. Language changed to a “gas detection log” to require a log of any kind that can detect gas indications behind casing.*

0015-40

§1726.7(f): In the context of the required inspection and leak detection protocol, commenter recommends including a definition for “protocol” in comparison to “plan” along with the addition of “monitoring” to the protocol name (“inspection, monitoring and leak detection”). Submission of the protocol should be required within 30 days of the effective date of the regulations. Commenter moved this requirement from the end of the section in subpart (f) to the beginning of the section at the end of subpart (a).

Response: *NOT ACCEPTED. The Division’s requirement for an inspection and leak detection protocol is clear, is already being implemented under the Division’s emergency regulations, and is only applicable until the California Air Resources Board has fully implemented its equivalent requirement.*

0023-1

§1726.7(f): Commenter indicates that the proposed monitoring requirements of this section should not limit gas storage operators to using infrared cameras only for compliance. While infrared imaging devices may perform well to detect leaks at locations with a dense number of components, the device will only detect emissions where the user focuses it. Factors that may affect find rates include sensitivity of the instrument, the skill level of the operator, and survey conditions such as wind speed, heat, and water vapor. Any bias introduced at the time of the survey will affect the repair history and propagate into the system integrity model. Infrared imaging devices have been estimated to require anywhere between three and seven hours to survey a well pad. Finally, the industry has stated that using infrared cameras often results in data

management problems such as having to catalog the thousands of images produced by the cameras.

Response: *NOT ACCEPTED. The reference to infrared imaging in this proposed section is provided as an example of a leak detection technology that would meet the needs of the proposed regulations. It is an example only and does not limit the operators to solely one method. Any limitations in the use of infrared cameras will have to be considered in the evaluation of results received from their use, but at this time the Division believes the technology to be of sufficient scientific validity and reliability to provide data that meets the performance standards of the proposed regulations.*

0023-2

§1726.7(f): Commenter requests that this section be amended to either include a reference to Cavity Ring-Down Spectroscopy technology or to any leak detection system that has a minimum detection threshold of 10 PPB (above ambient background levels), provides repeatable and reliable results, and produces records that are auditable at a reasonable cost.

0023-3

§1726.7(f): Commenter indicates that technologies exist which would allow for cost-effective daily or weekly surveys. Performing frequent surveys enables the operator to aggregate the data to quantify emissions; detect trends in emissions; and attribute emissions to various components at a facility. More frequent surveys reduce the cost per site per year, while contributing additional data for improved analytics on leak locations and emissions.

0023-4

§1726.7(f): Commenter provides leak detection services and recommends that their laser-based monitoring system be an approved monitoring method in the new regulations. The technology addresses the proposed monitoring requirements including response time, reproducibility, accuracy, immediate data availability through cloud based software analytics and reporting suite. It should be included in the proposed regulations because it allows for daily surveys of wellheads of gas storage projects (including the 100-foot radius) at a reasonable cost.

Response to 0023-2, 0023-3, 0023-4: *NOT ACCEPTED. One widely-accepted technology (infrared imaging) is provided as an example of the kind of leak detection technology that is acceptable to the Division. The proposed regulations do not prohibit the use of other effective technologies, but there is no need to include them when the*

example provided is not an exclusive requirement. The Division does not believe the specific standards proposed by commenter are necessary. The proposed regulations specify the needed frequency for testing surveys – daily.

0026-42

§1726.7(f): Regarding the reporting of gas leaks to the Division, Commenter recommends replacement of the requirement for “immediate” reporting with the phrase “as soon as practicable.”

Response: *NOT ACCEPTED. Leaks must be reported to the Division immediately so that it can monitor, inform, and coordinate response actions.*

0027-22

§1726.7(f): This section will cease to apply once CARB approves a monitoring plan under its regulations for the facility and will require additional review in light of the regulations CARB implements.

Response: *NOT ACCEPTED. For a project that has a monitoring plan that has been approved by CARB, the requirements of this subsection (f) will cease to apply, but only for that project under that plan. This will be the case no matter what regulations CARB implements, so no additional review will be required. Any project that does not have a CARB-approved monitoring plan will still be subject to these proposed requirements and all projects will remain subject to the other monitoring provisions of this section.*

0030-68

§1726.7(f): All wellhead and casing components should be inspected at least quarterly for not only corrosion, but also cracks and other conditions that may threaten well integrity.

Response: *NOT ACCEPTED. Daily visual inspection of the wellhead and casing components is required for cracks and other conditions that may threaten well integrity.*

1726.8 INSPECTION, TESTING & MAINTENANCE of WELLHEADS & VALVES

0015-38, 0052-14

§1726.8: In addition to these proposed regulations, existing regulations 1724.3 and 1724.4 also address sub-surface safety valves. Clarification is needed between the two sets of regulations. Moreover, existing regulations may also need updating.

Response: NOT ACCEPTED. Existing sections 1724.3 and 1724.4 apply to those wells which have been defined to be “critical wells” under section 1720. These proposed regulations do not affect that existing regulatory requirement. A gas storage well which meets the definition of “critical well” must meet the requirements of both 1724.3 and 1724.4 and the requirements of these proposed regulations.

0027-9

§1726.8: The proposed regulation does not provide requirements for calibration of gauges. Since the proposed regulation makes clear section 1724.10(e) does not apply to UGS projects, there is no current oversight for calibration of gauges.

Response: NOT ACCEPTED. It is the responsibility of the operator to engage in good oilfield practice, which includes maintenance of equipment and proper calibration of gauges and testing systems. The Division does not oversee every aspect of oilfield operation and cannot regulate the maintenance and calibration of every piece of equipment in an UGS project. RMPs created by operators will include proper preventative maintenance protocols based on risk assessments, which should include gauge maintenance in accordance with manufacturers specifications.

0010-30

§1726.8(a): Commenter recommends that testing take place at anticipated *maximum* operating pressures. This change goes toward enhancing the integrity of the surface equipment associated with gas storage wells, a critical safety barrier.

Response: NOT ACCEPTED. The ability to test to maximum operating pressures would be limited by the maximum pressure in the reservoir at the time of testing. Because a storage reservoir is rarely injected to maximum pressure, maximum operating pressures can rarely be achieved for this testing. Rather than delay testing until maximum operating pressures can be achieved, testing should be performed at anticipated pressure based on planned injection and withdrawal operations at least every six months.

0010-31, 15-49, 0027-21, 0030-49

§1726.8(a): Commenters recommend that operators be required to repair an inoperable safety valve or temporarily plug the well within 30 days of discovery of a failure rather than 90 days as permitted by the proposed regulations. If there is not an operational backup valve, all activity at the gas storage project should cease immediately, and the well temporarily plugged, until full repair is complete. This change goes toward

enhancing the integrity of the surface equipment associated with gas storage wells, a critical safety barrier.

Response: *NOT ACCEPTED. The majority of these repairs will require rig mobilization, which can take significant time depending on cost, availability, and site accessibility. It is unlikely to be practically feasible for operators to repair all inoperable valves within 30 days. Where the absence of a valve presents a hazard, operators will be required to perform a risk assessment and implement appropriate mitigation measures, up to and including shut-in of the well.*

0015-39

§1726.8(a): Commenter recommends increasing the testing frequency for surface and subsurface safety valve systems to 90 days from every six months.

Response: *NOT ACCEPTED. The Division has determined that the appropriate testing frequency based on the quality of equipment is six months, and that more frequent testing is not justified unless otherwise recommended by the manufacturer.*

0015-47

§1726.8(a): Commenter recommends including flapper valve and sliding sleeve door on the list of items which must be pressure tested every six months.

Response: *NOT ACCEPTED. The flapper valve is part of the subsurface safety valve and would be tested as part of that equipment test. The sliding sleeve or sliding sleeve door is a part of the casing; problems with it would be detected as part of the casing pressure test.*

0024-66

§1726.8(a): Commenter notes that surface safety valves fall under the jurisdiction of PHMSA. References to testing of surface valves should be removed.

Response: *NOT ACCEPTED. Surface safety valves are production facilities subject to regulation by the Division. Proposed section 1726.8(a) has been revised to only apply to surface valves on the wellhead so as to avoid duplication of PHMSA requirements implemented by the CPUC.*

0024-67

§1726.8(a): Commenter notes that API 14B only applies to subsurface safety valves. The test frequency included in the API references (appropriate standards for each type

of valve system) is as follows: API 14B applies to subsurface safety valves with a test frequency of at least every 6 months. API 14C applies to surface safety valves to be tested at least annually, with API 14H applying to surface safety valves with no regular testing requirement. Language requiring valve systems “to ensure ability to hold anticipated pressure at least every six months” should be deleted.

Response: *NOT ACCEPTED. The Division reviewed carefully the requirements of API RP 14B, 14C and 14H. The reference to API RP 14B is intended to refer to the testing procedures as described in that document, not the testing frequency. The Division does not see any value in different testing schedules for valves depending on location, which may lead to confusion as to the appropriate testing frequency required.*

0027-20, 30-48

§1726.8(a): The proposed regulation requires testing of surface and subsurface safety valve systems to at least every six months, but is self-policing. DOGGR staff has repeatedly waived their right to witness testing; the regulations should make it mandatory for DOGGR staff to be present.

Response: *NOT ACCEPTED. Proposed section 1726.8(a) requires operators to provide the Division with an opportunity to witness the valve tests, but it is not necessary to specify in regulation the percentage of tests that the Division will witness.*

0010-32

§1726.8(d): Commenter recommends that valves and similar equipment be required to meet API standards and be rated to withstand or exceed the maximum operations pressures. This change goes toward enhancing the integrity of the surface equipment associated with gas storage wells, a critical safety barrier.

Response: *ACCEPTED IN PART. A requirement that valves be rated to withstand or exceed the maximum operational pressures has been added to the proposed regulations.*

NOT ACCEPTED. The procedures for testing valves found in API RP 14B are referenced as an example of effective valve testing procedures, but adherence to the procedures in that document is not required. Other procedures may be employed, provided the Division agrees that the procedures employed will effectively confirm operational integrity.

0010-33

§1726.8(e): Commenter suggests concrete barriers or steel bollards be emplaced around all sides of the wellhead to act as barriers to protect the wellhead from potential damage and release of gas. This change goes toward enhancing the integrity of the surface equipment associated with gas storage wells, a critical safety barrier.

***Response:** NOT ACCEPTED. Commenter's requirements are too prescriptive. The need and type of protection for a well will be determined using the risk assessments under the RMP. Although in some cases concrete barriers or steel bollards may be appropriate, in others they be excessively costly given the risk. A blanket requirement for these extensive barrier systems is not appropriate.*

1726.9 WELL LEAK REPORTING

0025-39

§1726.9: The Division indicates in the Initial Statement of Reasons that it relied on the California Air Resources Board (CARB) proposed Oil and Gas Regulation to help determine what constitutes a “reportable leak” under PRC section 3183, subdivision (a). However, in addition to the Division’s proposed requirements, CARB also requires that, “[w]ithin 24 hours of receiving an alarm signaled by a downwind air monitoring sensor(s) that detects a reading that is greater than four (4) times the downwind sensor(s) baseline, the owner or operator shall notify the ARB, the Department of Oil, Gas, and Geothermal Resources, and the local air district to report the emissions measurement.” Cal. Code Regs., tit. 17, §§ 95673(a)(9). The Division should also include this in its regulation of what constitutes a reportable leak.

0015-51, 0027-26

§1726.9(a): As defined, this is inadequate because public health is affected at a lower ppm and thus would require a more stringent threshold level. Commenter thus recommends changing the threshold as follows: where the proposed regulations define a reportable leak as one that is above 50,000 ppm, commenter recommends a reduction to 5,000 ppm; where a reportable leak is defined as one that is above 10,000 ppm for more than five days, commenters recommend it be changed to 1000 ppm for more than five hours. Commenter notes that 50,000 is the lower explosive limit (LEL) and would represent an imminent danger of fire/explosion and any measure or human proximity poses an immediate risk.

0026-5

§1726.9: Commenter proposes the following definition of reportable leaks: "Equipment Leak means natural gas emissions that could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening. An Equipment Leak does not include intentional emissions or non-hazardous emissions that can be eliminated by lubrication, adjustment, or tightening." Use of the proposed definition would bring the proposed DOGGR UGS Projects regulations in alignment with the California Air Resources Board (CARB) Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities.

0015-50

§1726.9(a)(1): Commenter provides language for a narrative definition of "reportable leak." In contrast to the existing definitions which are identified by a measurement by volume total hydrocarbons, commenter's definition includes any leak from any project well that is measured using an approved methodology. If this definition is used, commenter recommends deletion of similar language regarding methodology from related subsections.

0008-5, 0030-61

§1726.9(a)(1): Required leak reporting should include all other surface facility and pipeline leaks not just leaks from a gas storage well. Operators should also be required to orally report to DOGGR discovery of any pressure changes, leak detection alarms, or other data that indicate the presence of leaks or lack of confinement in the gas reservoir immediately, with a written report quickly thereafter. The written report must be posted as part of the well record within five working days of receipt. There is no mention of public notification of gas leaks as they are only conveyed when an operator reports to CAL EMA and to local emergency responders.

0019-19

§1726.9(a)(2): Once a leak is detected above 10,000 ppm, continuous monitoring procedures should be put in place to ensure that levels do not exceed 50,000 ppm.

0030-50

§1726.9(b): If a gas storage well has a reportable leak, in addition to the requirement that the operator immediately inform the Division, the Division should be required to post reported leaks on its website within at least 3 days of receiving the report.

0030-51

§1726.9: The Division should be required to maintain a database of reported leaks, with information on any steps or measures taken to remediate or otherwise address them.

Response to 0008-5, 0015-50, 0015-51, 0019-19, 0025-39, 0026-5, 0027-26, 0030-50, 0030-51, 0030-61: NOT ACCEPTED. *The limited purpose of proposed section 1726.9 is to implement the specific requirements of PRC section 3183 and 3184. PRC section 3183, subdivision (c), requires that for a “reportable leak” that is not controlled within 48 hours, the Division must post information about the leak on its website and provide regular updates to the public until the leak is stopped. Public Resources Code section 3184 further requires that within 72 hours of being notified of a “reportable leak,” the Division shall make a determination as to whether the leak poses a significant present or potential hazard to public health and safety, property, or to the environment such that a relief well is necessary. If the supervisor makes that determination, the operator shall immediately begin preparation for, and, as soon as practicable at the determination of the supervisor, commence the drilling of a relief well.*

Public Resources Code section 3183, subdivision (a), requires the Division, in consultation with CARB, to adopt regulations defining a “reportable leak” and establish the timeframe for reporting such leaks to the Division. Proposed section 1726.9 responds to these statutory mandates. Commenters suggestions are beyond the scope of proposed section 1726.9 and they relate to issues that are addressed elsewhere in the Division’s and CARB’s regulations.

The requirement to report to the Division all surface and cellar gas releases, of any size from a gas storage well already appears in proposed section 1726.7(c) as part of the monitoring protocols. Daily inspections for leaks in the area around gas storage wellheads are addressed in proposed section 1726.7(f) and in equivalent requirements recently promulgated by CARB. Where a pressure change, alarm, or other data indicate a problem that falls under the jurisdiction of the Division, written reports and formal action may not be appropriate or cost-effective in all circumstances, such as a small leak easily controlled or a readily explained pressure change. However, all written reports of incidents would be included in the appropriate well or project files, which are made available on the Division’s public website in accordance with PRC section 3187. PRC section 3183 prescribes requirements for the Division to post information about reportable leaks on its public website.

0015-52

§1726.9(a)(3): In the context of a leak that poses a significant present or potential hazard, the terms “significant” and “potential” should be defined.

Response: *NOT ACCEPTED. The Division believes these terms are clear in context using their ordinary meaning and provide a clear qualitative standard; the operator is required to report to the Division any leak that has the capacity to pose a noteworthy present or future hazard to life, health, property, natural resources, or the environment.*

0015-53

§1726.9(b): Commenter recommends that in addition to informing the Division in the case of a reportable leak, the operator also be required to implement the ERP, provide a root cause analysis for the leak and an immediate remediation plan.

Response: *NOT ACCEPTED. This proposed section was developed in cooperation with CARB and is focused on the requirements for reporting a leak. It specifically does not contain any instructions as to how the operator must respond to the leak beyond reporting. Commenter is correct that the appropriate response is to implement the ERP; this is inherent in the proposed regulations’ requirement for the plan and does not need to be duplicated in this proposed section. Once a reportable leak has been identified, the Division and other agencies with jurisdiction, including local emergency response entities, will coordinate a comprehensive response in partnership with the operator based on the specific circumstances of the leak.*

0019-20

§1726.9(b): Language should be added to clarify that in the case of a reportable leak, the operator must immediately inform the Division and local authorities as required by law. This should be consistent with H&SC, Chapter 6.95, Article 1.

Response: *ACCEPTED IN PART. Proposed section 1726.9(b) requires operators to immediately inform the Division of reportable leaks. At that point, the Division would work with the operator to ensure that it is following its ERP and that other agencies are appropriately notified.*

0024-68, 0026-43

§1726.9(b): Commenters suggest the replacement of “immediately” with “as soon as practicable.”

Response: NOT ACCEPTED. In the case of any leak, the Division must be one of the first entities contacted immediately so that it can participate in the determination of appropriate response. “As soon as practicable” would suggest that the operator could contact the Division after the immediate crisis is over, providing a mere notification. Instead, the Division must be consulted immediately so that state resources can be mobilized to assist in appropriate response if needed. ERPs are required to include protocols for the notification of emergency response, state, and local agencies. Immediate notice to the Division should be planned for as part of this notification.

1726.10 REQUIREMENTS FOR DECOMMISSIONING

0024-10

§1726.10: Commenter appreciates the need to consult with the CPUC when submitting a Decommissioning Plan and that both agencies will need to be involved. However, commenter notes that the Division has not specified a process or timeline for its review and approval of a Decommissioning Plan, which should be added.

Response: NOT ACCEPTED. The Division is unwilling to commit itself to a timeline that might limit the ability to review a plan completely and to ensure that all risks, hazards, and safety needs are considered. Plans submitted by operators may be in various stages of completeness, the process of communication between the operator and the Division to cure deficiencies may take additional time. Staff availability and the varying size and complexity of projects will vary the time it will take to perform a thorough review. Rather than commit itself to a regulatory timeframe that might lead to incomplete review of the plan, the Division will take the time needed to ensure that the plan meets all regulatory requirements and will leave the site in good condition for planned future use.

0024-11

§1726.10: Commenter recommends that the requirements of the proposed regulations would only be applicable until the Division approves a Decommissioning Plan, thereby acknowledging that a project is no longer an underground storage project as defined under the jurisdiction of this regulation, though it might continue to be operated as a production facility for some time.

Response: NOT ACCEPTED. The project will remain subject to all UGS regulations, both existing and proposed, until such time as the approved Decommissioning Plan, and all the work required thereunder, has been certified as complete by the Division. This is necessary because the hazards to life, health, property, natural resources, and

the environment do not disappear just because a decommissioning plan is in place. Thus, any storage facility that is still being operated as a production facility after the approval of a decommissioning plan will remain subject to the regulations until the entire plan has been certified as complete. The Division will continue to monitor the project even after the decommissioning has been completed and approved and may, at any time, require re-entering and re-abandonment where appropriate.

0030-54

§1726.10: Decommissioning plans should be made available for public review and comment.

Response: *NOT ACCEPTED. The Decommissioning Plan will be focused on the safe shut down of well operations including plugging and abandonment of wells, and will be posted on the website for public information once it has been approved. Aspects of a Decommissioning Plan may necessitate a public comment process, but committing to a public notice and comment period for the creation of the plan may create unnecessary delay for the processing of a plan that will already be complicated by the number of regulatory agencies involved.*

0025-40

§1726.10(a): Properly closing gas storage sites is critical to protecting public health and safety and the environment. Commenter recommends revisions and additions, consistent with the best practices used in other states and jurisdictions (see e.g. K.A.R. 82-3-1011(f) and 40 CFR § 146.93). Specific revisions include the requirement for “a detailed schedule...in writing at least 120 days before site closure.” The plan should address the anticipated date of abandonment and decommissioning; anticipated field pressure at abandonment; plugging of all wells; identification of facilities to be abandoned; names of person who will be responsible for surface facilities; surface restoration including closure of surface impoundments; removal of any unused equipment, materials and debris; disposal of all wastes; and any other information required by the Division. Operators should be required to submit a site closure report within 90 days of closure, which the Division must retain for 10 years. The closure report must include documentation of well plugging and a survey plat showing the location of wells. Operators must record a notation on the deed that provides information to future purchasers regarding the use of the land for UGS, the name of the State agency holding the survey plat, and the volume of gas remaining in the storage reservoir.

Response: *NOT ACCEPTED. The detailed and prescriptive requirements suggested by commenter are not needed in the regulations. The Division’s oversight will be focused*

on the plugging and abandonment of the wells and site restoration at the wellhead. The shut-down and disposal of facilities and equipment as well as post-decommissioning field maintenance is the responsibility of the CPUC. Well location is already known and contained within Division files, which are maintained in perpetuity. Commenter's proposed timeframes are unrealistic since a decommissioning is likely to take two years or more and will require risk assessment and adaptation of the plan as each well is evaluated and then plugged and abandoned. Where a decommissioning plan may be submitted without information needed by the Division, it will not be approved until all aspects of the plan have been addressed so as to ensure the ongoing protection of life, health, property, natural resources, and the environment.

0024-69

§1726.10(a)(4): Commenter recommends moving the requirement to consult with the CPUC as part of a Decommissioning Plan from subsection (a)(4) to the main subsection (a) and adding a requirement to consult with the Division as well as seek its approval.

Response: *NOT ACCEPTED. As proposed section 1726.10 implements the Division's authorities and mandates, it is appropriate that consultation with the CPUC is referenced a critical element of the Decommissioning Plan, but is not included in the regulatory statement of the performance standard for the plan.*

0024-70

§1726.10(a)(4): Commenter recommends that a Decommissioning Plan should identify the date an underground gas project would no longer be used for storage.

Response: *NOT ACCEPTED. The date that a project will cease being used for active storage is only one factor in the evaluation of a Decommissioning Plan. The Division will approve a holistic plan that should include estimated dates for cessation of injection and withdrawal as well as provisions for any gas that will be removed from the reservoir prior to the final plugging and abandonment of all project wells, but a specific hard date that an UGS project will no longer be used for storage is not necessarily required.*

0027-27

§1726.10(b): The proposed regulation states the requirements for decommissioning a gas storage project and states that an UGS project is subject to this article "until the Division has approved a Decommissioning Plan and the Division has certified that the operator has completed all steps required under" the plan. This is inadequate for two reasons. It does not provide for continued monitoring once the project is

decommissioned and allows operators to go unchecked if their abandonment is not proper.

Response: *NOT ACCEPTED. The language that commenter references indicates that the wells and facilities would no longer be subject to the requirements for a UGS project, but not that the wells and facilities would no longer be subject to regulation by the Division. A well remains under Division jurisdiction and the operator remains responsible for it even after abandonment. The purpose of the regulatory language is to ensure that plugging and abandonment operations are inspected and completed according to the approved plan, making commenter's requirement for monitoring of improper abandonment unnecessary. The proposed regulations do not exempt the operator from continued liability for well safety after the abandonment is complete.*

MULTI-SECTION COMMENTS

0010-9

ALL SECTIONS: Throughout the proposed regulations, DOGGR leaves room for operators to propose alternative measures. This is appropriate, as a facility's particular circumstances may warrant a different approach than that prescriptively required by the agency, and it allows for regulations to be responsive to changes in technologies over time. However, the rule should articulate the standard by which such variances are approved. Some of the provisions in the proposed regulation suggest a standard, but not all do. The gist of the standard should be that the alternative approach is at least as effective and protective as the prescriptive approach provided in the regulation.

Response: *ACCEPTED. The Division endeavored to include clear performance standards in all instances where Division approval is required, and the Division made various revisions to the proposed regulations responding to comments indicating that the performance standard was not clear enough. For instance, language has been added to proposed section 1726.5(c) specifying that any alternative well construction method must include both primary and secondary mechanical well barriers, as various public comments suggested that it was not clear that two mechanical barriers would be necessary to achieve the performance standard articulated in subdivision (a) of that section.*

0027-25

§§1726.2(b), 1726.3(a) and 1726.4(a): The proposed regulations purport to protect "life, property or natural resources" but it is impossible to know what is being protected when the regulations do not specify the type of data that needs to be maintained and

disclosed to prove there is no damage to life, property or natural resources. Current regulatory text is inadequate because it does not determine a set schedule for review and leaves it up to chance whether any review will timely take place.

Response: *ACCEPTED. Specific data requirements imposed by the proposed regulations, as well as the data collected as part of risk assessments, are maintained and disclosed to the Division to assist in evaluating the potential for risk to the protected categories. The proposed regulations are a holistic, risk-based approach, using performance standards to ensure that UGS regulations are measuring and mitigating their impact on these protected categories. Compliance timeframes and timeframes and triggers for updates and review are included throughout the proposed regulations, and subsequent revisions to the proposed regulations addressed a number of gaps identified by commenters in this regard.*

0010-6, 0015-1

§§1726.2(c), 1726.3(a), 1726.4(d), 1726.5(a), 1726.9(a), and 1726.10(a): The Division must expand their goals and include the environment or environmental quality as a protected class.

Response: *ACCEPTED. The goal of protecting the environment is consistent with the Division's statutory mandates relating to UGS projects. Revisions to the proposed regulations inserted the word "environment" into general performance standard language throughout the regulations.*

0024-24

§§1726.3(a), 1726.4(a), 1726.4(d), 1726.5(d), and 1726.6(a)(1): Commenter recommends removing references for requirements to meet the "Division's satisfaction" as such language is vague and leads to uncertainty for operators on what may be required.

Response: *NOT ACCEPTED. The phrase "Division satisfaction" is used when an operator will propose a method or demonstrate use of an alternative to the default regulatory requirement. In various instances in the proposed regulations, the Division identified a default example, protocol, or configuration that could be used by the operator to comply with the required performance standard. Where an operator believes there is a better method of compliance, there is an opportunity to demonstrate that an alternative will meet the performance standard articulated in the regulation. The language that commenter finds "vague" is the compromise between a strict prescriptive requirement and no requirement at all, striking a balance between flexibility for*

operators based on risk and the need to hold operators accountable to protect public health and safety.

0031-3

§§1726.3(c), 1726.4(e), and 1726.4(a): There are insufficient definitions for terms such as “evaluation” (relating to geologic hazards in §1726.3(c)), “confidentiality” (relating to restrictions to access to records, such as through the California Public Records Act statutes in §1726.4(e)) and “fracture gradients” (which can change by use of an underground reservoir on §1726.4(a)).

Response: *NOT ACCEPTED. These definitions are not needed within the proposed regulations. The terms evaluation and fracture gradient are consistently used with their ordinary meaning.*

0027-7, 0030-2

§§1726.3(c)(2), 1726.4(a), 1726.5(b), 1726.6(a), 1726.7(f), 1726.8(a): Natural gas facilities have a significant history of acute dangers. While it is important to try to minimize these dangers, it is also important to evaluate whether they pose ongoing chronic impacts and risks as well. Therefore, the Center recommends that, prior to issuing any discretionary permits or approvals, DOGGR conduct health and seismic risk assessments, as well as review under CEQA.

Response: *NOT ACCEPTED. Permitting for a new intrastate UGS project is initially under the control of the CPUC and permitting for a new interstate UGS project is initially under the control of the Federal Energy Regulatory Commission (FERC). Both the CPUC and FERC permitting process include comprehensive environmental review and extensive opportunity for comment. Once permitted by the CPUC or FERC, the operator would apply to the Division for project approval.*

0015-22

§§1726.3(c)(5) and 1726.7(d)(1): Commenter recommends the inclusion of annular spaces and tubing in the required monitoring under the RMP. Monitoring should be expanded to include temperature and composition of fluids, liquids and gases as well as pressures. The term “facility” in the context of “facility flow erosion” and “facility component capacity” should be defined and compared to system, equipment, wells or project.

Response: *ACCEPTED IN PART. Proposed section 1726.7(d)(1) has been revised to clarify that monitoring of the real-time data gathering system should include every*

casing annulus and tubing. Proposed section 1726.3(c)(5) [now 1726.5(d)(5)] to include liquid “flow” rates and “temperature” ranges as part of the ongoing monitoring requirement under the RMP.

NOT ACCEPTED. The evaluation of the corrosive impact of temperature and composition was added as part of the considerations for corrosion mitigation under proposed section 1726.3(d)(4)(B), but specific monitoring is not required unless indicated by the risk assessment and prevention and mitigation protocols.

0010-27

§§1726.3(c)(11) and 1726.7(b)(2): Commenter suggests detailed requirements for observation wells, including a provision as to how they should be used, an explanation as to where they should be placed, and to what standards they should be constructed. These requirements are consistent with the considerations in the *UGS Regulatory Considerations (Interstate Oil and Gas Compact Commission/Ground Water Protection Council, May 2017)*. Specifically, the requirement for “monitoring” by “installed” observation wells should be expanded to include the “geological formation being utilized for observation.” Commenter also provides specific siting and monitoring requirements to, including that wells be installed in the vicinity of spill points, depending on the geology of the project, provided that they are located in areas capable of being monitored. Considerations for location include placement within the buffer zone to limit artificial penetrations; potential migratory paths; fluid interface monitoring; permeable zones and stratigraphic traps; and low permeability zones, formations or fields in communication with the storage zones. Commenter also suggests that observation wells be constructed to the standards and criteria of this chapter.

Response: *NOT ACCEPTED. The requirements proposed by commenter are overly prescriptive and observation wells are already subject to other well construction requirements. In addition, observation wells are just one form of acceptable reservoir monitoring. The proposed regulations allow for any monitoring method which will meet the performance standard. This flexibility is needed to ensure operators can select the best methods for their site circumstances. Proposed reservoir monitoring methods must be approved as part of the RMP.*

0010-39, 0015-7, 0027-23, 0030-5

§§1726.5(b) and 1726.6(a): The Division must specifically prohibit any use of production casing for “casing flows” during injection or withdrawal. No sleeves, no doors, no flappers. This dangerous practice further threatens the integrity of old wells and poorly understood hydrogeology, and undermines the safety otherwise gained by

these regulations. While it important to cover such possibilities, it is imperative that DOGGR restrict injection to the tubing only.

Response: *NOT ACCEPTED. In a well with a single casing and inner tubing, it would be appropriate to limit flow to tubing only, as that would be necessary for the casing and tubing configuration that most commonly be used to meet the “no single point of failure” well construction standard. However, a single casing with production tubing is not the only way to meet the performance standards of the proposed regulations. Thus, a blanket requirement limiting flows to tubing only would not be appropriate.*

0015-4, 0030-65, 0035-3

§§1726.5(b) and 1726.7(b): The operator must submit all initial records and supporting information that have been independently verified and certified designs and approvals as to being “as-is/as-built” and “as approved.” Where digital data is transmitted to the Division, it must also be independently verified by a licensed engineer and/or specialist in gas storage. Commenters specifically apply this verification requirement to overall well configuration, production casing, remedial cement slurry, operator proposed alternate methods for achieving well construction performance standards, reservoir monitoring, semi-annual field shut-in tests, and gas movement methods. For production casings, commenter recommends that independent verification be performed by a State registered engineer with five years of Oil and Gas Exploration and production experiences. Independent verification of testing data must also be provided.

Response: *NOT ACCEPTED. Requiring that all data be “independently verified” would add substantial complexity, burden, and ambiguity to the proposed regulations without clear benefit.*

0015-37, 0052-13

§§1726.6(d) and 1726.8(a): Video recording of mechanical integrity testing should be conducted and transmitted to the Division in real-time, not just notifying the “appropriate district office...at least 48 hours before...so that Division staff *may* have an opportunity to witness the testing.” These digital recordings must be available for review by the public anytime that they want, online, and in real time. Ensuring the appropriateness of testing will be a vital component of quality control, especially after the Aliso Canyon blow-out. As it seems likely that Division staff will often not be available to witness testing in-person, especially with only 48 hours’ notice, video recording would be the most effective method of quality control. Commenters emphasize that this requirement should also be specifically applied to all surface and subsurface valve systems, with

inspections, testing, and operations of these valve systems being transmitted in real-time to the Division and District staff.

Response: *NOT ACCEPTED. It is unlikely that video recording of operational activities would add any value to regulatory enforcement, and is thus unlikely to be cost-effective given the cost of equipment and maintenance. This is primarily because “witnessing” is not effective via video. The multi-sensory experience and ability to test or direct repeat operations when present cannot be replaced with a recording that is just a visual record. For a mechanical integrity test, the value of witnessing is limited, because the primary enforcement tool is evaluation of the log and testing results. The inclusion of the 48-hour notice requirement will facilitate more witnessing by Division staff.*

0010-40

§§1726.7(d)(3)(E), 1726.7(e), and 1726.9(b): Commenter suggest adding a requirement that, upon discovery of serious problems (as defined by each section), “operators must shut in the well unless doing so presents additional safety issues.” As currently proposed, in many cases, operators must report the problems they find to the Division, but are not explicitly required to take any direct action on the problematic well. This formulation would reduce the risk of catastrophic releases.

Response: *NOT ACCEPTED. Where the Division determines that it is justified by potential risk or known hazard, it may order a shut-in at any time. A specific provision is not needed in the proposed regulations to make this possible. In addition, many serious problems can be addressed without the need to shut-in a well. Whenever such risks or hazards have been identified, the Division works with the operator to develop an immediate response plan, which may include shut-in, but such a requirement is not needed as a default.*

OTHER EDITS SUGGESTED WITHOUT DISCUSSION

0010-41

Commenters recommend a variety of edits without explanation throughout the regulations as follows:

§1726.1(a)(1): ...in a three-dimensional perspective image. *NOT ACCEPTED. The proposed language does not appear to add any additional meaning or clarity.*

§1726.1(a)(4): ...from an underground gas storage project. *ACCEPTED.*

§1726.1(a)(5): ...is being used or has been converted to store... *NOT ACCEPTED. The proposed language does not appear to add any additional meaning or clarity. .*

§1726.2(a): ...before any injection or withdrawal occurs... *ACCEPTED.*

§1726.2(b) & (c): ...rescission by the Division by Administrative Order..., ...written notice by Administrative Order from the Division... *NOT ACCEPTED. Where life, health, property, natural resources, or the environment may be threatened, the Division must have the ability to modify, suspend, or rescind approval to mitigate the threat.*

§1726.3(b)(3):to reduce, manage or monitor risks... *ACCEPTED.*

§1726.3(b)(7): ...three years and also in response.... *NOT ACCEPTED. The proposed language does not appear to add any additional meaning or clarity.*

§1726.3(c)(1): ...well construction, cementing, and design... *NOT ACCEPTED. Cementing is part of well construction which is already listed.*

§1726.3(c)(1): ...a work plan with time schedule for... *ACCEPTED.*

§1726.3(c)(2): ...evaluation of whether installation ~~employment~~ of surface.... *NOT ACCEPTED. "Installation" is a lesser requirement; a valve could be installed but not used. "Employment" includes use, which meets the goal of the regulation.*

§1726.3(c)(2)(B): Gas composition, operational pressures, total fluid flow... *ACCEPTED.*

§1726.3(c)(2)(J): ...in the local general plan... *ACCEPTED.*

§1726.3(c)(3): ...demonstration of the external and internal mechanical integrity of each well used in the UGS project..." *NOT ACCEPTED. This language is not necessary. The requirement here for mechanical integrity is for the well as a system not just internal or external integrity.*

§1726.3(c)(3): ...and any each well that penetrates into or drilled through ~~intersects~~ the reservoir used for gas storage within the area of review. *NOT ACCEPTED. The proposed language does not appear to add any additional meaning or clarity. .*

§1726.3(c)(4)(A): ...tubular and casing integrity and... *NOT ACCEPTED. "Tubular" includes all things in the shape of a tube, including casing. Addition of the recommended language is unnecessary.*

§1726.3(c)(5): ...monitoring of all casing pressure... *NOT ACCEPTED. Language as written already includes all changes.*

§1726.3(c)(10): ...the potential for explosion and/or fire. *ACCEPTED.*

§1726.3(c)(15): ...response plan that at a minimum accounts for the threats... *ACCEPTED.*

§1726.3(d): ...Risk Management Plan unless a variance has been... *NOT ACCEPTED. The proposed language does not appear to add any additional meaning or clarity.*

§1726.4(a): ...zone(s) of injection and withdrawal and that the underground...of the Division Supervisor, are pertinent... *ACCEPTED IN PART. "Supervisor" has been changed to "Division." "Withdrawal" of fluids does not carry the same risk as injection, and the issue of concern for this section is migration of fluids during injection. Thus, the addition of "withdrawal" is not correct here.*

§1726.4(a)(4)(A): ...to inject and withdrawal fluids, particularly... *NOT ACCEPTED. The inclusion of "withdrawal" is not correct in this section, which is focused on pressure limits during injection. In fact, withdrawal is generally considered a mitigation measure in this context.*

§1726.4(a)(4)(A): ...well constructions, well heads, surface piping, or associated facilities. *NOT ACCEPTED. The use of the word "wells" in this context includes the entire well as an integrated system. The addition of "constructions" is a limiting term which is not needed. "Piping" was used in error and has been corrected to "pipelines." Both surface and subsurface are purposely included.*

§1726.4(a)(4)(B): ...stress and potential liquid influx. *NOT ACCEPTED. This analysis should not be limited to "potential" influx but should consider actual and potential impacts.*

§1726.4(a)(5): ...another adjacent well or well penetration, geologic traps such as structure, pinchout, facies change, faults...fissures, or loss-breach the integrity of casing integrity any holes in casing. The... *NOT ACCEPTED. This section is a list of examples of potential migratory pathways, but is clearly not intended to be an exhaustive list. The recommended additions appear to simply be more examples and additional descriptive details which do not provide additional clarity.*

§1726.4(a)(5)(B): Reservoir characteristics of each storage ~~injection~~ zone, such as porosity... *ACCEPTED.*

§1726.4(a)(5)(B): ...gradient, storage reservoir(s) original and present bottom-hole temperature... *NOT ACCEPTED. Bottom-hole temperature of the storage wells is not the concern being addressed in this section. The characteristics of the reservoir, not the infrastructure, are the subject of this requirement.*

§1726.4(a)(5)(C)(i): ...geologic marker bed at or near the top... *NOT ACCEPTED. The proposed language does not appear to add any additional meaning or clarity.*

§1726.4(a)(5)(C)(iv): Representative geophysical logs ~~electric log~~ to a depth below the deepest gas storage ~~producing~~ zone identifying all... *ACCEPTED IN PART. A geophysical log is the more correct term, however it need only be a*

single log, not “logs” because each log will have three or more tracks. Storage is not the same as production, so that change was also accepted.

§1726.4(a)(5)(F): Complete wellbore diagrams...and that penetrate into or through the gas storage reservoir are in the same or a deeper zone as the gas storage...diagrams and well records must demonstrate...all perforations (or open-hole interval)... **NOT ACCEPTED.** *These changes appear to be a more complicated way of saying the same thing. All diagrams submitted should always be “complete”; specifying completeness is unnecessary. Description of wells is functionally the same; no additional wells would be included or excluded based on the recommended change. It is insufficient for “well records” to show activities related to proper cementing; casing diagrams are needed to show the cement has been fully emplaced in the proper locations and through the proper zones. Any additional documentation needed would be identified in the permit for plugging and abandonment.*

§1726.4(a)(5)(G): ...below the well total depth. **NOT ACCEPTED.** *The proposed language does not appear to add any additional meaning or clarity.*

§1726.4(a)(5)(H): Wells completed into or penetrating... **NOT ACCEPTED.** *The proposed language does not appear to add any additional meaning or clarity. .*

§1726.4(a)(5)(H): ...operation volumes, pressures, and flow... **ACCEPTED.**

§1726.4(a)(5)(H): ...operator ~~should~~ shall identify... **ACCEPTED.**

§1726.4(a)(5)(H): ...integrity testing or ~~well~~ geophysical logging in order... **NOT ACCEPTED.** *This section is focused on internal well logs, not evaluation of external geophysical characteristics.*

§1726.4(a)(5)(J): ...underground disposal wells and disposal zones horizons, mining... **ACCEPTED IN PART.** *The recommended language was added and expanded for clarity.*

§1726.4(a)(6)(A): ...surface injection and withdrawal pressures and maximum anticipated and daily rate of injection and/or withdrawal, by well. **NOT ACCEPTED.** *This section is concerned with maximum pressures and rates of injection to assist in evaluating actual risk related to pressurized injection. Withdrawal in this context is a mitigation measure, in that it can be used to relieve pressure and reduce this injection related risk. Thus, concern with maximum pressures and daily rates is not applicable to withdrawal.*

§1726.4(a)(6)(C): ...of leaks and monitoring of pressures. **NOT ACCEPTED.** *Monitoring of pressures is provided for in other sections.*

§1726.4(f): ...treatment per the California Public Records Act or relevant federal law, then the... **NOT ACCEPTED.** *All laws governing the release of documents handled by public agencies are presumed to apply unless a specific exemption or exception can be demonstrated. This language is unnecessary.*

§1726.4.1(a)(1)(G): ...equipment such as surface and subsurface... *NOT ACCEPTED. The surface valve is not part of a casing diagram as it is outside the Christmas tree/master gate valve assembly.*

§1726.4.1(a)(1)(H): Depths of casing shoes, stubs... *ACCEPTED.*

§1726.4.1(a)(1)(I): ...perforation intervals, open-hole completions, water shutoff... *NOT ACCEPTED. This information would be evident from the diagram and the specific data is not needed.*

§1726.4.1(a)(1)(N): ...geologic markers beds penetrated... *NOT ACCEPTED. The proposed language does not appear to add any additional meaning or clarity.*

§1726.4.1(a)(3): ...directionally drilled or horizontal wells...azimuth measurements, ~~and~~ surface and bottom-hole location. *NOT ACCEPTED. Horizontal wells are included in the larger category of “directionally drilled” wells and do not need to be separately listed. All the preceding requirements of this section also apply to directionally drilled holes (they are called out here to list additional requirements that ONLY apply to directionally drilled holes, but all other requirements would still apply); bottom-hole location is already required.*

§1726.5(a): ...design, construct or convert, and maintain... *ACCEPTED IN PART. “Modify” was added instead of “convert.”*

§1726.5(b)(1)(A)(ii): Casing and Tubing hanger with seals... *NOT ACCEPTED. This is just an example of a well configuration that would meet the standards, it is not intended to impose specific prescriptive requirements.*

§1726.5(b)(1)(A)(iii): Injection or production ~~Production~~ tubing... *NOT ACCEPTED. This is just an example of a well configuration that would meet the standards, it is not intended to impose specific prescriptive requirements.*

§1726.5(b)(1)(B)(ii): Production and/or intermediate Casing. *NOT ACCEPTED. This is just an example of a well configuration that would meet the standards, it is not intended to impose specific prescriptive requirements.*

§1726.5(b)(2): ...internal and external operating pressures... *NOT ACCEPTED. There is no such thing as an external operating pressure.*

§1726.5(b)(3): ...support subsequent drilling and injection/production operations. *NOT ACCEPTED. The edit would not add clarity.*

§1726.5(b)(4)(5): ...compatible with well and operational fluid chemical... *NOT ACCEPTED. There is no distinction between operational fluid and well fluid.*

§1726.5(b)(4)(5): ...maximum expected operational pressures... *ACCEPTED.*

§1726.5(b)(4)(5): ...casing shall be is free of open...*NOT ACCEPTED. The proposed language does not appear to add any additional meaning or clarity.*

§1726.5(b)(6)(7): ...or porosity throughout ~~through~~ the wellbore... *NOT ACCEPTED. The subdivision has been otherwise revised.*

§1726.5(b)(7)(8): ...wellbore conditions and operational pressures. All casing... *NOT ACCEPTED. Operational pressures are part of wellbore conditions and are already included in the existing language.*

§1726.5(b)(7)(8)(A): ...annular space from the casing shoe to the surface... *NOT ACCEPTED. Language is clear as written.*

§1726.5(b)(9)(10): ...slurry or other sealants and placement...formations, pressures, and type... *NOT ACCEPTED. Cement slurry is the only permitted sealant, so "other sealants" language is not appropriate. "Pressure" is a wellbore condition so it is already included.*

§1726.5(b)(10)(11): ...bond log or cement evaluation logs... *NOT ACCEPTED. Evaluation could include something other than a log.*

§1726.5(b)(10)(11): ...cement bond providing hydraulic isolation extends across... *NOT ACCEPTED. The Division is unaware of any data the operator could use to prove this.*

§1726.5(b)(11)(12): ...packer, packer shall be is set in a cemented section of the production casing within...~~or at a location acceptable to the Division.~~ *NOT ACCEPTED. This is just an example of a well configuration that would meet the standards, it is not intended to impose specific prescriptive requirements.*

§1726.6(a): ...conduct the following internal mechanical... *NOT ACCEPTED. Mechanical integrity testing is required for all parts of the well, and is not limited to internal integrity.*

§1726.6(a)(3)(2): ...production casing of all withdrawal/injection wells shall be... *NOT ACCEPTED. The wells covered by this requirement are specified at the beginning of this subsection in 1726.6(a). The language proposed by commenter would exclude observation and other wells penetrating the gas storage zone that are intended to be included.*

§1726.7(a): ...recording annular pressure and injection pressure at least... *NOT ACCEPTED. Monitoring of injection pressure already takes place when injection is being performed and is provided to the Division monthly. Injection pressure is not the issue of concern for monitoring regulations in this context, which is focused on the integrity of the primary barrier at all times, not just during injection operations.*

§1726.7(b)(1): ...average reservoir operating pressure versus gas inventory... *NOT ACCEPTED. There is no such thing as a reservoir "operating" pressure; reservoir pressure fluctuates with operations but does not have an operating pressure itself. When dealing with UGS, "inventory" always refers to the gas inventory including reservoir water and cushion gas.*

§1726.7(b)(4): ...gamma ray-neutron or other Division approved geophysical logs to confirm... *NOT ACCEPTED. Language as proposed already allows for*

operator choice of log, gamma ray is provided as example only. All monitoring methods must be included in the RMP for review and approval by the Division. Any test performed which does not meet the standards of the RMP would be rejected by the Division.

§1726.7(d)(1): ...every casing annulus and tubing and data transmission to an operations... *ACCEPTED.*

§1726.7(c)(2): ...allowable surface pressure. For the annulus annuli between production... *NOT ACCEPTED. The proposed language does not appear to add any additional meaning or clarity.*

§1726.7(d)(3)(E): ...action as needed to correct the problem in... *NOT ACCEPTED. The proposed language does not appear to add any additional meaning or clarity.*

§1726.7(e): ...shall conduct as ~~Neutron~~ Gamma Ray-Neutron logging, or equivalent... *ACCEPTED IN PART. This test has been renamed a "gas detection log" for clarity.*

§1726.7(f): ...infrared imaging (or other Division approved methods), and shall provide... *NOT ACCEPTED. The requirement for Division approval of the protocol appears in the previous paragraph, which will include approval of the intended inspection technology to be used.*

§1726.8(a): ...storage project shall function test all surface... *NOT ACCEPTED. Testing of a valve is by necessity a function test.*

§1726.8(a): ...testing a safety valve... *ACCEPTED.*

§1726.8(b): ...storage project shall function and pressure test the... *NOT ACCEPTED. A function test is part of a pressure test so to include both would be redundant. However, neither is needed because this section is a performance standard which can be met by any testing method which will demonstrate proper function and verify ability to isolate the well.*

§1726.10(a)(3): ...decommissioning or permanently plugging and abandoning all wells and... *NOT ACCEPTED. Permanent plugging and abandonment of each well in a gas storage project would be one option under the decommissioning plan, as would conversion to another use. Plugging and abandonment should not therefore be considered an alternative to decommissioning, but a part of the process.*

0015-48

Commenters recommend a variety of edits without explanation throughout the regulations as follows:

§1726.3(a): ...for review and consideration approval. The Risk... *NOT ACCEPTED. The Division must approve the RMP, not just consider it. A plan that*

does not meet requirements will be rejected with explanation and correction and improvement will be required until the RMP is approved by the Division.

§1726.3(a): ...the approved zones of injection, storage, and withdrawal and that the underground... *ACCEPTED IN PART. This proposed section was revised to clarify that gas must be confined during all phases of operational activity.*

§1726.3.1(c)(3): Prepositioning as ~~feasible~~ and identification of...to respond to releases, blowouts and leaks, including...and stop the release leak itself as... *NOT ACCEPTED. The terms "release" and "leak" are not interchangeable because there are planned releases, such as flares, which would not require emergency response.*

§1726.3.1(c)(3)(4): An annual schedule for regular.... *NOT ACCEPTED. Drills should be scheduled as frequently as needed to ensure that personnel are trained in emergency response and prepared to respond. This may mean drills more frequently than annually, or possibly less frequently. The appropriate frequency for emergency drills must be determined based on operational and community conditions such as local emergency response time, personnel expertise and turnover rates, changes in operational conditions, and any other risk, which would make more frequent drills appropriate.*

§1726.3.1(c): 4 – 5 – 6 – 7 – 8 – 9 Renumbering required. *ACCEPTED.*

§1726.3.1(c)(9)(10): ...a large uncontrollable release leak to any potentially... *NOT ACCEPTED. The terms leak and release are not interchangeable. A planned release, such as a flare would not be subject to this requirement. This language comes directly from statute.*

§1726.5(a): ...construct, monitor, and maintain underground gas storage project wells to effectively...for the underground gas storage project. The operator...of fluids and gases and make... *NOT ACCEPTED. This section is focused on well construction and maintenance requirements. Ongoing monitoring requirements are found in another subsection.*

§1726.5(b)(1): ...barriers to isolate the ~~storage gas~~ within the storage...and transfer storage gas and fluids from the...out of the storage reservoir. *NOT ACCEPTED. The proposed language does not appear to add any additional meaning or clarity.*

§1726.5(b)(1)(B): ...as demonstrated by quarterly ~~periodic~~ tubular annular pressure...and casing and liner evaluation logs...the leaking fluids and gases until the primary... *NOT ACCEPTED. The reference to periodic annular pressure testing has been removed and replaced with a cross reference to the testing requirements for pressure testing and casing evaluation logs.*

§1726.5(b)(3): ...subsequent drilling, completion, and rework operations. *NOT ACCEPTED. This section is specific to surface casing, which must be of*

sufficient quality to support a drilling rig and drilling operations. Completion and rework operations do not require the same level of equipment and thus do not require the same strength of casing.

§1726.5(b)(4): ...compatible with fluid and gas chemical composition...accommodate fluids, gases, and other phases during an injection, storage, and withdrawal at the...production casing must be is free of...~~other than the planned completion interval(s).~~ *NOT ACCEPTED. The term “fluids” has been defined to include liquids and gases; other phases are not relevant to UGS. The Division sees no justification for prohibiting open perforations for planned completion intervals.*

§1726.5(b)(7): ~~The e~~ Cementing operations used a cement slurriesy designed for...All casings are was... *NOT ACCEPTED. The proposed language does not appear to add any additional meaning or clarity.*

§1726.5(b)(7)(A): ...to the surface. ~~to protect groundwater.~~ *NOT ACCEPTED. Cementing to the surface is not always appropriate or safe. Instead, the performance requirement “to protect groundwater” is the goal of cementing.*

§1726.5(b)(8): ...for effective zonal isolation of all fluids, gases... *NOT ACCEPTED. Complete zonal isolation is required, thus modifying terms are not appropriate and weaken the regulatory requirement.*

§1726.5(b)(9): ...conditions, formations, zones, and type of... *NOT ACCEPTED. The features of the zones a well passes through are encompassed in the requirement to design for the specific wellbore conditions and formations. The addition of “zones” does not add meaning or clarify the requirement.*

§1726.5(b)(10): ...bond logs for all project wells ~~or evaluation acceptable to the Division~~ are conducted, verified and submitted to and is on filed with the Division that indicates an...and bore walls ~~geologic formations.~~ A competent... *NOT ACCEPTED. This section outlines requirements that apply to every gas storage well. Expanding it to all project wells is not intended or appropriate when those wells have different levels of risk and configuration needs. Division approval of the logging method is a required element and cannot be removed. See response to Comment 0015-4 regarding verification. Operators must ensure that the cement is adequately bonded to the formation holistically, not just attached to the bore walls.*

§1726.7(a)(b): ...shall monitor, measure, record, verify, and provide to the Division for the...all annuli ~~by measuring and recording annular pressure at least...~~ shall evaluate daily any anomalous...immediately report such anomaly it to the...gathering system, ~~such as Supervisory Control and Data Acquisition.~~ *NOT ACCEPTED. The proposed changes do not appear to change the meaning*

of the subsection or create clarity. See response to Comment 0015-4 regarding verification.

§1726.7(b)(c): ...shall monitor, measure, record, verify and provide to the Division the material balance (including fluids, liquids, and gases) behavior of...storage project's storage reservoir...reservoir behavior for temperatures, pressures, and volumes for fluids and gases, including waters. The operator shall...Monitoring frequency must ~~should~~ be based on all relevant factors, such as...well fluid and gas loss potential and flow and migration potential as outlined...by the Division. Division-approved Acceptable reservoir integrity...analysis methods shall include any of the following, or an equally effective method approved by the Division... *NOT ACCEPTED. The proposed changes do not appear to change the meaning of the subsection or create clarity. See response to Comment 0015-4 regarding verification.*

§1726.7(b)(2): ...located observation and other project wells in the... *NOT ACCEPTED. This section is specifically about observation wells and their use as reservoir integrity monitoring tools and does not include any requirements or restrictions that would apply to non-observation wells.*

§1726.7(b)(3): ...offset hydrocarbon and other liquids production, injection, withdrawal, or disposal... *NOT ACCEPTED. The Division can think of no "other liquids" production that would be appropriate for consideration under this section. Injection and withdrawal would be included as part of production activities and water produced during or for hydrocarbon production would be captured by this requirement. Where groundwater wells may be near the project, the RMP requires identification of associated hazards and mitigation where appropriate.*

§1726.7(d)(2): ...than the maximum approved allowable surface... *NOT ACCEPTED. The need for the maximum pressure to be approved is inherent in the inclusion of the word "allowable."*

§1726.7(e)(f): ...Division, on each project ~~gas storage~~ well... *NOT ACCEPTED. This section provides two distinct requirements, one for gas storage wells, and one for all wells in the project. It is not intended that these requirements be the same for all project wells.*

§1726.8(a): ...or a Division approved equivalent... *ACCEPTED.*

§1726.9(a)(1)(2): Any leak from a gas storage project well that is above... *NOT ACCEPTED. The proposed language does not appear to add any additional meaning or clarity.*

§1726.9(a)(2)(3): Any leak from a gas storage project well that is above... *NOT ACCEPTED. The proposed language does not appear to add any additional meaning or clarity.*

§1726.9(a)(3)(4): Any detectable (50-1000 ppm) leak that poses...safety, property, natural resources, or... *NOT ACCEPTED. See response to comments 0008-5, 0015-50, 0015-51, 0019-19, 0025-39, 0026-5, 0027-26, 0030-50, 0030-51, and 0030-61.*

§1726.9(b): ...a gas storage project well has a... *NOT ACCEPTED. The proposed language does not appear to add any additional meaning or clarity.*

§1726.9(c): ...a gas storage project well. *NOT ACCEPTED. The proposed language does not appear to add any additional meaning or clarity.*

0024-61

Commenters recommend edits without explanation as follows:

§1726.4(a): ...proposed project as requested. The data... *NOT ACCEPTED. The proposed language does not appear to add any additional meaning or clarity.*

§1726.7(b)(2): ...located observation wells in the storage reservoir, in the vicinity... *NOT ACCEPTED. There may be circumstances where observation wells are needed outside the reservoir to identify migrations or effects that may be occurring outside the geologic formation because of project operations.*

0026-38

§1726.6(a)(2): Commenters suggest edits to requiring casing wall thickness inspection “~~at one least~~” to “at least once”. *ACCEPTED.*