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M E M O R A N D U M

TO:	Chairman Christi Craddick Commissioner Wayne Christian Commissioner Jim Wright
FROM:	Haley Cochran, Assistant General Counsel Office of General Counsel
THROUGH:	Alexander C. Schoch, General Counsel
DATE:	August 22, 2023
SUBJECT:	Amendments to 16 TAC Chapter 5, relating to Carbon Dioxide (CO2)

Attached is Staff's recommendation to adopt amendments to 16 Texas Administrative Code Chapter 5, relating to Carbon Dioxide (CO2). The amendments ensure that the rules are as stringent as the requirements of the U.S. Environmental Protection Agency (the "EPA") to support the Commission's application to EPA for enforcement primacy for the federal Class VI Underground Injection Control (UIC) program.

The Commission adopted initial regulations to implement the Class VI UIC program effective December 20, 2010, and amended those regulations in 2022 to reflect changes in the Texas statutes and to ensure that the state's program meets the minimum federal requirements for Class VI UIC wells. The State submitted to EPA its official application for primacy on December 19, 2022. In March 2023, EPA provided comments and recommended rule amendments in a few areas. These amendments are intended to respond to EPA's recommendations.

On June 13, 2023, the Commission approved the publication of the proposed amendments in the Texas Register for a public comment period, which ended on July 31, 2023. Staff recommends that the Commission adopt the amendments with changes to the proposed text as published in the June 30, 2023, issue of the *Texas Register* (48 TexReg 3452). The recommended changes are described in the attached adoption preamble.

cc: Wei Wang, Executive Director
Danny Sorrells, Assistant Executive Director and Director of the Oil and Gas Division
Leslie Savage, Chief Geologist

The Railroad Commission of Texas (the "Commission") adopts amendments to §5.102 (relating to Definitions) in Subchapter A; and in Subchapter B adopts amendments to §§5.201 and 5.203 - 5.207 (relating to Applicability and Compliance; Application Requirements; Notice of Permit Actions and Public Comment Period; Fees, Financial Responsibility, and Financial Assurance; Permit Standards; and Reporting and Record-Keeping, respectively), with changes to the proposed text as published in the June 30, 2023, issue of the *Texas Register* (48 TexReg 3452). The Commission adopts changes in §§5.102, 5.201(h), 5.201(i), 5.203(b), 5.203(f), 5.203(k), 5.204(a), 5.205(c) and (i), 5.206(d), 5.206(e), 5.206(f), 5.206(g), 5.206(k), 5.206(m), and 5.207(b).

The Commission adopts the amendments to ensure that the rules are as stringent as the requirements of the U.S. Environmental Protection Agency ("EPA") to support the Commission's application to EPA for enforcement primacy for the federal Class VI Underground Injection Control (UIC) program.

EPA protects underground sources of drinking water (USDWs) by regulating the injection of fluids underground for storage or disposal. The Safe Drinking Water Act (SDWA) and the UIC program provide the primary regulatory framework. From the early 1980s until 2010, EPA regulated five classes of wells according to the type of fluid injected, the depth of injection, and the potential to endanger USDWs. Historically, most states have sought and been granted primacy over one or more classes of wells. For example, most states have primacy over Class II wells, in which fluids are injected for natural gas and oil production, hydrocarbons storage, and enhanced recovery of oil and gas.

In 2010, EPA promulgated rules creating a sixth well class (Class VI) specifically to regulate the injection of carbon dioxide ("CO_2") into deep subsurface rock formations. EPA established minimum technical criteria for permitting, site characterization, area of review and corrective action, financial responsibility, well construction, operation, mechanical integrity testing, monitoring, well-plugging, post-injection site care, and site closure requirements.

Under the SDWA, EPA may delegate its authority to implement and enforce the UIC program to states upon application. If EPA approves a state's application, the state assumes primary enforcement authority (i.e., primacy) over a class or classes of wells. Until a state receives primacy, EPA directly implements the UIC program through its regional offices.

The State of Texas has established a statutory framework for projects involving the capture, injection, sequestration or geologic storage of anthropogenic carbon dioxide. The statutes require the state to pursue primacy for the Class VI UIC program. After almost a decade of little interest, interest in carbon capture and geologic sequestration or storage has increased over the past several years prompting the Commission to resume efforts to gain primacy for the Class VI UIC program.

The Commission adopted initial regulations to implement the Class VI UIC program effective December 20, 2010, and amended those regulations in 2022 to reflect changes in the Texas statutes and to ensure that the state's program meets the minimum federal requirements for Class VI UIC wells. The State submitted to EPA its official application for primacy of the Class VI UIC program on December 19, 2022.

Included in that application was a cross-walk comparison (i.e., a table comparing state and federal requirements). In March of 2023, EPA provided comments to the cross-walk comparison and recommended rule amendments in a few areas. These amendments respond to EPA's recommendations.

The Commission received 30 comments – 6 from associations (Greater Houston Partnership, Reliable Energy Alliance, Texas Chapter of National Association of Royalty Owners, Texas Chemical Council, Texas Industry Project, and the Texas Oil and Gas Association); 2 from companies or organizations (Environmental Defense Fund and Commission Shift) and 21 from individuals. The Commission also received one comment submitted on behalf of the following Texas-based organizations and individuals ("the Texas-based Organizations"): Air Alliance Houston, Another Gulf is Possible Collaborative, Bayou City Waterkeeper, Better Brazoria: Clean Air & Water, Carrizo Comecrudo Tribe of Texas, Chispa Texas, Clean Energy Now Texas, Clean Water Action, Coalition of Community Organizations, Coastal Alliance to Protect our Environment, Coastal Bend Sierra Club, Commission Shift, Fair Housing and Neighborhood Rights, Fenceline Watch, For the Greater Good, G-Forensic, Greater Edwards Aquifer Alliance, Healthy Gulf, Heiko Stang, Ingleside on the Bay Coastal Watch Association, Lone Star Chapter, Sierra Club, Mi Familia Vota, New Liberty Road Community Development Corporation, Port Arthur Community Action Network, Property Rights and Pipeline Center, Public Citizen, Rio Grande International Study Center, Sanbit, Inc., Sister Elizabeth Riebschlaeger, Texas Campaign for the Environment, Texas Environmental Justice Advocacy Services, and Turtle Island Restoration Network. The Commission appreciates these comments.

General Comments

The Texas Chemical Council (TCC) and the Texas Oil and Gas Association (TXOGA) generally support the Commission's application for primacy from the EPA for the permanent geologic sequestration and storage of carbon dioxide via Class VI underground injection control wells. TCC and TXOGA greatly appreciate both the EPA and the Commission's efforts towards achieving that goal.

The Texas Industry Project (TIP) expressed the belief that carbon capture and storage is a critical tool for reducing carbon dioxide in the atmosphere, and that Texas is uniquely situated to become a national leader in geologic storage of carbon storage. TIP stated that it understands the Commission's proposed amendments to its Chapter 5 rules are intended to support the Commission's application for authority to enforce the federal Class VI UIC program in Texas by ensuring that the Commission's rules are at least as stringent as EPA's Class VI rules and to respond to comments from the EPA on the Commission's current rules. TIP expressed support both the proposed amendments and the Commission's request for primacy to administer the Class VI UIC program in Texas.

The Reliable Energy Alliance (REA) expressed support for the proposed amendment designating the Commission as the sole authority in the state over onshore and offshore injection and geologic storage of anthropogenic CO_2. REA also supports the Commission's application for primacy from EPA for administration of the Class VI injection well program. Streamlining the regulation of Class VI injection in Texas to one state agency will encourage and expedite the use of carbon capture utilization and storage (CCUS) in the state. REA believes Texas must support the CCUS industry to protect its oil and gas industries that employ hundreds of thousands of Texans. Our nation depends upon Texas' fossil fuels production, and Texas needs to be ready to meet future demand. Texas can meet the growing energy in demand from its oil and gas production, and CCUS can be an optional component of that when producers desire to decarbonize any process where carbon is a byproduct. As global energy demand continues to grow, supporting and growing the CCUS industry in Texas will be vital to ensure the state's fossil fuel industry meets increasing energy demand while having options to control CO_2 emissions.

The Greater Houston Partnership expressed support for the proposed amendments and the furtherance of carbon capture use and storage in Texas. The rapid innovation and progress of the Texas energy industry and its advancements in lower-carbon technologies such as CCUS require a robust regulatory framework. If Texas is to remain a global leader in CCUS, we must pursue regulatory policies and procedures to streamline the permitting process. By allowing the Commission to have sole regulatory authority and primary jurisdiction over Class VI wells, we create a stronger regulatory pathway to achieving the development of large-scale CCUS investments and help advance our state's energy competitiveness. We applaud the Commission and EPA for their collaboration and commitment in working to ensure the effective implementation and oversight of this framework.

The Commission appreciates the support of these commenters.

Ms. Diane Teter commented that carbon dioxide should be regulated by congressional mandate. Mr. Patrick A. Nye commented that geologic storage of carbon dioxide is in its infancy of development. The Commission should align with EPA for the first five years of time to ensure the health and safety of the populations at risk as well as groundwater. Until there is a real reform and acknowledgement of climate change and the safeguards to environmental justice communities as well as all communities, EPA should rule. Mr. Nye opposed the Commission taking over the Class VI program and stated that EPA should show the safer way forward.

Ms. Cyndi L. Valdes, Ms. Diane Teter, Ms. Julie Nye, Ms. Bess Willis, Ms. Becky Rector, Ms. Bonnie Vechell, Ms. Ann R. Nyberg, and the Texas-based Organizations expressed opposition to the Commission having primacy for the Class VI program because they believe that the Commission has an inherent conflict of interest because they receive campaign donations by the industries they regulate. The number of uncapped wells in Texas is growing every day and the Commission cannot keep up with the current job they have. The Commission has a horrible track record of enforcing regulations and will fail to protect residents who reside next to potential carbon dioxide storage. Ms. Valdes commented that she does not want the storage next to communities and elementary schools. Ms. Linda Bennett commented that, without close oversight and precise engineering on these carbon injection facilities, so much risk could occur and the Commission does not have the capabilities, manpower, structure to handle either of these very necessary components to be the overseeing regulatory agency. Ms. Julie Nye and Ms. Bennett expressed the belief that the Commission is not the proper authority to regulate carbon sequestration because it has a history of not enforcing current regulations on the oil and gas industry. Mr. Don McCown commented that, while the proposed new Chapter 5 rules would be an improvement over the current statute, he shares Commission Shift's concern that federal regulations for carbon dioxide injection do not take into account Texas-specific issues, and that the Commission's new rules will not be strong enough to protect land and communities.

The Commission notes that in the federal Safe Drinking Water Act of 1974 (Act), Congress directed EPA to develop underground injection regulations to guide states in establishing their own programs. Congress intended that the states have the responsibility for enforcement of the Act, provided the state program meets minimum federal requirements. State law provides that the Commission has exclusive jurisdiction over geologic storage of carbon dioxide (Texas Water Code, §27.041). State law (Texas Water Code, §27.048) requires that the Commission seek federal primary enforcement authority for the Class VI underground injection control program. Furthermore, in order for EPA to grant primacy to Texas, the Commission's requirements must meet the minimum federal requirements. The states are in the best position to address state-specific issues and conditions. The Commission's review of applications for the geologic storage of carbon dioxide will take into account the specific conditions at the proposed project location.

With respect to the Commission's UIC program, EPA performs annual evaluations of the Commission's UIC program performance. These annual evaluations have been positive. EPA Region 6's 2021 annual evaluation acknowledged that the Commission's UIC program compliance surveillance and enforcement program for Class II and III injection wells regulated by the Commission appears to be effective. A large percentage of the permitted injection wells in Texas were inspected in FY 2020 and the Commission also collected and reviewed operator-submitted monitoring information from a large percentage of the Class II well inventory. Those numbers assure more than adequate inspection and monitoring surveillance actions. The 2021 annual evaluation specifically noted innovative measures taken by the Commission to address program challenges, such as induced seismicity and continued improvements of data reporting and recordkeeping.

Mr. Brian Hillman, Ms. Malinda Huffman, Mr. Francisco Martinez, Ms. Leslie Meyer, and Ms. Meg Davis expressed concern about the issue of carbon dioxide injection and the risk these projects pose to the health and safety of the land, water, and communities. Injecting highly pressurized carbon dioxide waste deep into the earth can pose risks to our communities. Without consistent oversight, harmful materials like lead, arsenic, and strong acids can leak into underground sources of drinking water. The Commission has a responsibility to ensure the highest possible safety conditions for the people and places of Texas that will be impacted by this new carbon waste disposal technology.

Similarly, Ms. Linda Bennett and Mr. Andy Davis expressed concern with carbon sequestration or carbon dioxide injection and the risk these projects might pose to water and land in Texas. Ms. Bennett commented that she has not seen the science that would allow her to act on the financial opportunity that might be realized through the leasing of their pore space. Ms. Bennett expressed concern that there is no way that the injected carbon dioxide can be restrained accurately underground and not cause harm to our neighbors through trespass into their pore space. Ms. Bennett expressed concern that the injected carbon dioxide will migrate back up to the surface in an unintended location, causing damage and potential human risks. She requested that Texas approach this venture cautiously and potentially wait to see how the science turns out from the two carbon sequestration sites that are up and running in the U.S. Ms. Bennett requested that the science become public knowledge so Texans can make educated decisions on this issue. Mr. Beau Bennett expressed concern about introducing carbon injection under Texas soil and stated that he does not believe that the science proves that carbon sequestration can be done safely. Mr. Bennett further commented that migration of the carbon dioxide would be extremely costly and damaging to Texas and its residents.

Geologists Mr. Patrick A. Nye and Mr. Payton Campbell also expressed concern that geologic storage of carbon dioxide has yet to be proven safe and reliable. They stated that although the Commission has a long history of managing various well types in the past, Chapter 5 as written does not resolve the complexities in the evaluation process to minimize risks to the health and safety of residents and groundwater within or near the area of review. Injection sites appear to be more of an area of convenience than that of a scientific thought-out evaluation with sound geoscience evidence. Mr. Patrick A. Nye and Mr. Payton Campbell asked what assurances the Commission would enact for the protection of the public's health and safety.

The Commission disagrees that geologic storage of carbon dioxide is unproven technology. In its most recent Working Group III report *Climate Change 2022: Mitigation of Climate Change* report, the International Panel on Climate Change (IPCC) reaffirmed the central role that CCUS will play reducing carbon dioxide levels in the atmosphere. Carbon capture and storage technologies have been proven at commercial scale and there is an extensive network of global knowledge about carbon dioxide storage. Geologic storage of carbon dioxide for the purpose of reducing carbon dioxide emissions began in 1996 with the Sleipner project in Norway. Today, there are 12 commercial scale facilities capturing and safely storing carbon dioxide in the United States.

Long-term geologic storage of carbon dioxide is possible with today's technology. The federal Class VI rule, and the Commission's rules, build on existing underground injection control program requirements, with extensive tailored requirements that address carbon dioxide injection for long-term storage to ensure that wells used for geologic sequestration are appropriately sited, constructed, tested, monitored, funded, and closed. These regulations include specific criteria for Class VI wells, such as extensive site characterization requirements, injection well construction requirements for materials that are compatible with and can withstand contact with carbon dioxide over the life of a geologic storage project, injection well operation requirements, comprehensive monitoring requirements that address all aspects of well integrity, carbon dioxide injection and storage, and ground water quality during the injection operation and the post-injection site care period; financial responsibility requirements assuring the availability of funds for the life of a project (including post-injection site care and emergency response); and reporting and recordkeeping requirements that provide project-specific information to continually evaluate Class VI operations and confirm USDW protection. The applicant is required to demonstrate the presence of an adequate confining zone consisting of a geologic formation, group of formations, or part of a formation stratigraphically overlying the injection zone that acts as a barrier to fluid movement. In addition, the applicant is required to take action to correct any penetration into the injection zone to eliminate the potential that that penetration could act as a conduit for injected fluids to migrate to another zone or to the surface.

The Commission does agree that, as with any activity, there are potential risks associated with the geologic storage of carbon dioxide. However, the federal and state regulations are designed to mitigate those potential risks. The rules are based on the existing underground injection control regulatory framework, with modifications to address the unique nature of CO_2 injection for geologic storage. These rules establish a new class of well, Class VI, and set minimum technical criteria for Class VI wells for the purposes of protecting underground sources of drinking water. The rules set minimum technical criteria for Class VI wells to protect underground sources of drinking water from endangerment, including: site characterization that includes an assessment of the geologic, hydrogeologic, geochemical, and geomechanical properties of the proposed geologic storage site to ensure that Class VI wells are located in suitable formations; computational modeling of the area of review that accounts for the physical and chemical properties of the injected CO_2 and is based on available site characterization, monitoring, and operational data; periodic reevaluation of the area of review to incorporate monitoring and operational data and verify that the CO_2 plume and the associated area of elevated pressure are moving as predicted within the subsurface; well construction using materials that can withstand contact with CO_2 over the life of the project; robust monitoring of the CO_2 stream, injection pressures, integrity of the injection well, ground water quality and geochemistry, and monitoring of the CO_2 plume and position of the pressure front throughout injection; comprehensive post-injection monitoring and site care following cessation of injection to show the position of the CO_2 plume and the associated area of elevated pressure to demonstrate that neither pose an endangerment to underground sources of drinking water; and financial responsibility requirements to ensure that funds will be available for all corrective action, injection well plugging, post-injection site care, site closure, and emergency and remedial response.

When injected into an appropriate receiving formation, CO_2 is sequestered by a combination of trapping mechanisms, including physical and geochemical processes. Physical trapping occurs when the relatively buoyant CO_2 rises in the formation until it reaches a stratigraphic zone with low permeability (i.e., geologic confining system) that inhibits further upward migration. Physical trapping can also occur as residual CO_2 is immobilized in formation pore spaces as disconnected droplets or bubbles at the trailing edge of the plume due to capillary forces. A portion of the CO_2 will dissolve from the pure fluid phase into native ground water and hydrocarbons. Preferential sorption occurs when CO_2 molecules attach to the surfaces of coal and certain organic rich shales, displacing other molecules such as methane. Geochemical trapping occurs when chemical reactions between the dissolved CO_2 and minerals in the formation lead to the precipitation of solid carbonate minerals. The timeframe over which CO_2 will be trapped by these mechanisms depends on properties of the receiving formation and the injected CO_2 stream. The effectiveness of physical CO_2 trapping is demonstrated by natural analogs in a range of geologic settings where CO_2 has remained trapped for millions of years. For example, CO_2 has been trapped for more than 65 million years under the Pisgah Anticline, northeast of the Jackson Dome in Mississippi and Louisiana. Other natural CO_2 sources include the McElmo Dome, Sheep Mountain, and Bravo Dome in Colorado and New Mexico.

Many of the injection and monitoring technologies that may be applicable to geologic storage are commercially available today and will be more widely demonstrated over the next 10 to 15 years. The oil and gas industry has over 35 years of experience of injection and monitoring of CO_2 in the deep subsurface for the purposes of enhancing oil and gas production. This experience provides a strong foundation for the injection and monitoring technologies needed for commercial-scale geologic storage.

Ms. Diane Teter commented that the new permit system for carbon dioxide is not designed for so many risks that this untested transport pipeline/hub system poses. CO_2 is a corrosive gas and when mixed with various water impurities and other gases as NOx and SO2, the full consequences are unknown.

The Commission notes that the rules require the chemical composition and physical characteristics of the carbon dioxide streams be known as part of the initial permitting process, as well as during operation of the well, to ensure that these carbon dioxide streams can be injected in a manner that is protective of human health and the environment and underground sources of drinking water. The rules address the quality and quantity of impurities by requiring operators to submit information on the source of the carbon dioxide and its physical and chemical properties. Specifically, the rules require the operator to submit data about the site, including an analysis of the chemical and physical characteristics of the carbon dioxide stream and information on the compatibility of the carbon dioxide stream with fluids in the injection zone and minerals in both the injection and the confining zones and the materials used to construct the well. This information can help the director determine the potential for geochemical reactions between the injectate (the carbon dioxide stream) and the host geologic formations, which could result in the plugging of pore spaces or the dissolution of formation minerals. Analysis of the carbon dioxide stream will provide information about any impurities that may be present and whether such impurities might alter the corrosivity of the injectate down-hole. Such information is necessary to inform well construction and the project-specific testing and monitoring plan and enable the operator to optimize well operating parameters while ensuring compliance with the Class VI permit. The analysis of the carbon dioxide stream must be conducted prior to commencing injection and throughout injection operations at an appropriate frequency based on the source of the carbon dioxide stream and the likelihood of variability in the injectate composition. The details of the sampling process and frequency must be described in the director-approved, site-specific testing and monitoring plan.

Neither the federal rules nor the Commission's rules set generic purity standards for carbon dioxide injectate streams (e.g., a percent carbon dioxide). The injection of carbon dioxide streams, including incidental associated substances derived from the source materials and the capture process, can be performed in a protective manner at a permitted UIC Class VI well. Regardless of the precise contaminants, and their concentrations, the UIC Class VI permitting requirements take into account the physical and chemical characteristics of the carbon dioxide stream as part of establishing the appropriate conditions for the successful confinement of the CO_2 in a manner that is protective of underground sources of drinking water.

Ms. Teter commented that there is a whole geologic ecosystem beneath the earth's surface which will be impacted and the consequences are unknown. Ms. Teter also commented that there are geologic sites which are hazardous and/or incompatible with CO_2 storage and should be disseminated to the public.

The Commission notes that Class VI permit applicants must provide extensive information about the local and regional geology and hydrogeology of a proposed geologic storage site. Both the federal and state regulations require an applicant to characterize the geologic storage site and to demonstrate that the proposed site is suitable for the geologic storage of carbon dioxide. The applicant must demonstrate that the area has a suitable geologic system, consisting of an injection zone with sufficient capacity to receive the volume of carbon dioxide proposed to be injected, and a confining zone that is free of transmissive faults or fractures. Information concerning the characterization of the site will be provided to the public through the draft permit and fact sheet that the Commission is required to prepare in accordance with §5.202.

Mr. Paul Gingrich commented that Enbridge has a terrible track record for safety and staying within pollution limits. He believes its project would be better served in a larger metro area like Houston where resources and response to any issues arising can be better dealt with and where it would not be adjacent to his residential population. The project presents an unnecessary danger to water wells, which many people use in the proposed project area.

The Commission does not understand this comment. The Commission has not received an application from Enbridge.

EPA commented that 40 CFR §144.52(b)(2) and (3) are missing from the state regulations.

The Commission notes that the requirements of 40 CFR §144.52(b)(2) and (3) are located in §5.206(o)(2)(P).

Mr. Patrick A. Nye and Mr. Payton Campbell recommended that the Commission form a new Class VI division to include a team of licensed petroleum engineers, licensed geoscientists, petrophysicists, geochemical geologists, and geophysicists to evaluate each aspect of the application and operations and that this team report to the Commission and the director rather than the director having sole discretion. Mr. Patrick A. Nye, Mr. Payton Campbell, and Ms. Cyndi L. Valdes commented that as Chapter 5 is written, it is clear the director would have too much power to control all aspects of the Class VI decision making. These commenters asked for clarification as to how the engineering, petrophysical, geochemical, geological, and geophysical checks and balances that would ensure public safety and freshwater protection will be disseminated to the director.

The Commission notes that because of the extent and complexity of the information that must be reviewed in response to Class VI permit applications and evaluated throughout the operational and post-injection phases of a Class VI project, the Commission plans to implement a team approach. The duties and responsibilities for the Class VI UIC program will predominantly be handled by Underground Injection Control (UIC) staff of the Oil and Gas Division of the Railroad Commission. The Class VI UIC Manager (a geologist or engineer) will have a significant technical management role in the program, supervising a team of geologists and engineers selected for the Class VI UIC team on the basis of their experience and expertise. Staff have in-house expertise (and access to outside contractors, if needed) with skills in the technical and policy areas relevant to evaluating Class VI permit applications, issuing Class VI permits, and overseeing geologic storage projects throughout the life of the projects.

Mr. Patrick A. Nye and Mr. Payton Campbell commented that the operator should be penalized for non-compliance with the timing and monitoring regarding reports sent to the Commission. Mr. Nye and Mr. Campbell commented that reporting of the status of the well integrity, equipment, and the area of review is critical to adherence to the EPA rules and asked whether the Commission will levy penalties and fines for non-compliance. Mr. Nye and Mr. Campbell also requested information as to how the Commission will assess penalties for non-compliance of the permit. The Organizations asked whether the Commission will potentially assign violations or penalties for non-compliance based on failure to submit reports, submitting incomplete reports, or reports indicating that an underground source of drinking water is at risk without remedial actions having been described. The commenters also requested clarification as to whether penalties will be greater than the cost of noncompliance.

The Commission has the authority to pursue enforcement action, including penalties, for noncompliance with the requirements of Subchapter B and a permit. The Commission's enforcement process is described in Appendix C (Office of General Counsel Enforcement Process) in the Fiscal Year 2023 Oil & Gas Monitoring and Enforcement Plan, which can be found at rrc.texas.gov/media/2bwbeqtk/o-g-monitoring-enforcement-plan-fy-2023.pdf.

The Commission makes no changes in response to the comments previously discussed.

Regarding the Commission's proposal preamble, Mr. Patrick A. Nye and Mr. Payton Campbell commented that Commission jurisdiction to ensure standards comply with federal requirements of EPA set up special interest-bearing funds consisting of penalties. This alone will require more personnel. Further, Mr. Patrick A. Nye and Mr. Payton Campbell recommended that the Commission increase personnel to review applications and compliance until assurances can be made that it is safe for public health and water.

The Commission does not understand the first part of this comment. With respect to the need for additional personnel, the Commission will devote additional resources to the program as the program grows to meet or exceed requirements for program performance. The Commission makes no change in response to this comment.

Mr. Patrick A. Nye and Mr. Payton Campbell commented that micro-businesses may have a higher risk of bankruptcy and potentially avoidance of compliance. They recommended that micro-businesses should have receipts of $2 million and should include AI or any corporation financially able to secure development and dissolution of facilities.

The comment concerns language in the preamble relating to the requirements of Texas Government Code, §2006.002, relating to Adoption of Rules with Adverse Economic Effect. The term "micro-business" is defined in Texas Government Code §2006.001 and cannot be changed by the Commission. The Commission does not anticipate that micro-businesses will apply for Class VI permits under Subchapter B. The Commission makes no change in response to this comment.

Rule-specific comments

§5.102

Mr. Robert F. Van Voorhees expressed support for the proposed amendments to the definition of anthropogenic carbon dioxide at §5.102(2). This is a very important revision to clarify that direct air capture is included as a means of capturing anthropogenic CO_2.

TCC and TXOGA expressed support for the amended definition in §5.102(2) of anthropogenic carbon dioxide to include carbon dioxide that has been captured from, or would otherwise have been released into, the atmosphere. This revision clarifies the applicability of the regulations to carbon dioxide resulting from direct air capture technologies. TCC and TXOGA also expressed support for the corresponding revision to the definition of "carbon dioxide (CO_2) stream" in §5.102(7). And, both commenters expressed support for the revisions to the definitions of "anthropogenic CO_2 injection well" in §5.102(3) and "geologic storage" in §5.102(28) to clarify that the regulations apply to the various phases of carbon dioxide (i.e., gaseous, liquid, or supercritical). This revision is consistent with the federal Class VI UIC regulations, which refer to different phases of carbon dioxide.

Mr. Van Voorhees also supports the amendment to the definition of "geologic storage" in §5.102(28), stating that it is important to clarify that the regulations apply to the various phases of carbon dioxide (gaseous, liquid, or supercritical) for consistency with the federal Class VI UIC regulations. Mr. Van Voorhees expressed support for the amendments to the definition of §5.102(30) and stated that it is important to acknowledge that an operator and the owner of the pore space may use various mechanisms to grant the legal right to access and use the pore space. Mr. Van Voorhees expressed support for the amendment to §5.102 to add a definition for stratigraphic test well and stated that the Commission should adopt the revision as proposed to recognize the importance of allowing injectivity testing in a stratigraphic test well to improve the success of geologic sequestration projects.

The Commission appreciates the support of these commenters.

NARO-TX recommended that the Commission revise the definition of "good faith claim" in §5.102(30) to recognize rights of mineral owners in underground geologic formations, including within and near geologic storage facilities. NARO-TX recommended the Commission define good faith claim as: "a factually supported claim based on a recognized legal theory to a perpetual property interest*, including all mineral interests*, in pore space to be used for geologic storage of carbon dioxide . . ."

TXOGA recommended that the definition for "good faith claim" be removed rather than amended because a good faith claim, as referenced in §5.206(b)(9), is a determination to be made by the applicant based on the property interests it needs and the property interests it has obtained and does not require definition by the Commission. However, if the Commission sees the need to define this term, TXOGA notes that the proposed definition modifies good faith claim to encompass "a perpetual property interest" rather than "a continuing possessory right." TCC and TXOGA commented that this would drastically change the nature of said property interest and contrasts with how the term has been used in other Commission regulations. See, e.g., 16 TAC §3.15(a)(5) relating to Surface Equipment Removal Requirements and Inactive Wells. As a result, the proposed definition broadens the scope of a good faith claim beyond how it has been used previously without clear explanation and could be construed to exclude the use of certain types of property interests, such an easement, which may be utilized for certain activities. Therefore, if the term must be defined, TCC and TXOGA requested that the Commission revise the proposed definition to refer to "continuing possessory right" or "continuing property interest."

In response to these comments, the Commission has revised the definition of "good faith claim" to "a factually supported claim based on a recognized legal theory to a *continuing possessory right* in pore space, *such that the pore space* can be used for geologic storage of carbon dioxide."

EPA commented that there are many instances where EPA regulations reference "owner or operator" but the state regulations only use the term "the operator." Similarly, TXOGA requested clarification on the Commission's use of "operator" throughout the Class VI UIC well provisions as opposed to "owners and operators" as used in the federal regulations. For reference, "operator" is defined in § 5.102(21) as a "person, acting for itself or as an agent for others, designated to the Railroad Commission of Texas as the person with responsibility for complying with the rules and regulations regarding the permitting, physical operation, closure, and post-closure care of a geologic storage facility, or such person's authorized representative." "Owner" is undefined. The federal UIC regulations at 40 CFR §144.3 state that "the owner or operator of any 'facility or activity'" are subject to regulation under the UIC program. TCC and TXOGA requested clarification on how the use of "operator" as opposed to "owner and operator" will impact the applicability of these provisions on their members.

The Commission notes that 40 CFR §144.3 defines "owner or operator" as the owner or operator of any "facility or activity" subject to regulation under the UIC program. The Commission holds the "operator" responsible for permitting and compliance. The Commission has defined “operator” at §5.102(38) as a “person, acting for itself or as an agent for others, designated to the Railroad Commission of Texas as the person with responsibility for complying with the rules and regulations regarding the permitting, physical operation, closure, and post-closure care of a geologic storage facility, or such person's authorized representative.” Although the Commission holds the “operator” responsible for compliance, the Commission agrees that, if the owner and operator are two different entities, either may demonstrate financial responsibility. Therefore, the Commission has added definitions for “owner or operator” and for “owner” and has changed “operator” to “owner or operator” in the sections relating to financial responsibility.

The Commission also notes that EPA granted primacy to North Dakota for its Class VI UIC program and the North Dakota regulations at Chapter 43-05-01 use the term “operator” rather than “owner or operator.” In addition, the Commission’s Class III brine mining regulation at 16 TAC §3.81 relating to Brine Mining Injection Wells, for which EPA granted primacy under Section 1422 of the Safe Drinking Water Act, uses the term “operator.”

EPA commented that “Director” should be capitalized.

The Commission declines to make changes in response to EPA’s comment because the Commission finds that whether the term is capitalized is not material. The definitions of “Director” and “State Director” in 40 CFR §144.3 both use the term “director” (lower case). In addition, EPA granted primacy to the state of North Dakota, whose regulations at Chapter 43-05-01 use the term “commission” (lower case) in lieu of “Director.” Furthermore, the Railroad Commission’s brine mining rule at 16 Texas Admin. Code §3.81 was approved by EPA effective March 29, 2004, under Section 1422 of the Safe Drinking Water Act and uses the lower case “director.”

TXOGA commented on the issue of defining “stratigraphic wells.” In §5.201 (relating to Applicability and Compliance), TXOGA highlighted that “stratigraphic wells” are a newly defined term and are not included in EPA regulations. Operators are currently encountering challenges in other states with the emerging regulation of stratigraphic and other carbon sequestration-related wells under traditional oil and gas rules. While it makes sense to regulate certain wells under the Commission’s oil and gas rules to leverage existing processes and programs, stratigraphic wells do not have any relationship to oil and gas. Thus, while TXOGA believes the Commission is the appropriate agency to manage these wells, TXOGA recommended a clear delineation between the programs to avoid creating an opportunity to mischaracterize stratigraphic wells as oil and gas wells.

The Commission defined the term “stratigraphic test well” in §5.102 as “An exploratory well drilled for the purpose of gathering information in connection with a proposed carbon dioxide geologic storage project, including formation testing to obtain information on the chemical and physical characteristics of the injection zones and confining zones. Such testing may include injectivity testing.” One purpose for adding this definition and the corresponding language in §5.202(h) was to clarify that such wells are not injection wells, and are, therefore, not subject to the federal Underground Injection Control program requirements. Another purpose for adding both the definition and the language in §5.202(h) was to clarify that an operator must apply for a permit to drill prior to drilling a stratigraphic test well, must comply with the requirements for drilling and completing the well, must submit a completion report once the well is completed, and must comply with the requirements to plug the well. In addition, the Commission added the definition and the language in §5.202(h) to ensure that any operator who drills a stratigraphic test well and plans to later convert the well to a Class VI injection well knows that the well must be constructed in compliance with the Class VI injection well requirements of Subchapter B, Chapter 5. The Commission finds the language is warranted and makes no change in response to this comment.

§5.201

Mr. Van Voorhees expressed support for the amendment to §5.201(h) requiring an operator to apply for a permit to drill (Form W-1) prior to drilling a stratigraphic test well, notify the UIC Section of the application, and submit a completion report (Form W-2/G-1) once the well is completed. Mr. Van Voorhees stated that the provision that clarifies the availability of conversion for stratigraphic test wells to Class VI wells. It also provides useful guidance on what compliance is required for construction of the wells.

The Commission appreciates this comment.

TCC and TXOGA commented that the proposed language in §5.201(h) requires an operator to "apply for a permit to drill (Form W-1) prior to drilling a stratigraphic test well, notify the UIC Section of the application, and submit a completion report (Form W-2/G-I) once the well is completed." Under this provision, if the operator plans to convert the stratigraphic test well to a Class VI injection well, the well construction shall meet all requirements of this subchapter for a Class VI injection well. Any stratigraphic test well drilled for exploratory purposes only shall be governed by the provisions of the Commission's rules in Chapter 3 applicable to the drilling, safety, casing, production, abandoning, and plugging of wells. TCC and TXOGA note that this differs from current regulations, as Class V wells would not generally be subject to primacy requirements under the Class VI program. TCC and TXOGA requested clarifying language regarding these requirements. Practically, this revision seems to require that the ultimate purpose of the well be predetermined, and the well be constructed for that purpose before knowing whether and how the well can even be used, nullifying the need for an exploratory well in the first instance. Specifically, the commenters requested that the regulation be revised so that it is evident that these requirements are not applicable to wells that are not subsequently converted to Class VI injection wells or are converted to Class V injection wells. An example of such a well could be a monitoring well. TCC and TXOGA fully understand and support there may be additional well criteria upon conversion but disagrees with any requirement that applies such heightened requirements speculatively.

The Commission disagrees. Both the federal rules and the Commission's rules require that an operator have a permit under the Class VI regulations before constructing the well. The Commission understands that some operators plan to drill a stratigraphic test well and convert that well to a Class VI well in the future. Therefore, that well must be constructed to meet the Class VI injection well requirements. As noted, the Commission finds that the stratigraphic test well is a type of "exploratory well" not subject to underground injection control regulations. Nor is a stratigraphic well a Class V well under the Commission's program. The Commission anticipates that operators will "predetermine" the use of these wells. The Commission makes no change in response to this comment.

Additionally, TXOGA requested that §5.201(h) be further amended to state that an operator may obtain data from site characterization though offset well data in the field as an alternative to drilling a stratigraphic test well.

The Commission partly agrees and adopts §5.201(h) with a change. The Commission also deleted the reference to "production" in this subsection because stratigraphic wells are not "production" wells.

The Texas-based Organizations commented that §5.201(h) would allow operators to drill a stratigraphic test well and convert that test well to a Class VI well later on. This would allow an initial borehole to be drilled before an operator confirms complete financial assurance for well plugging and before interested parties receive notice of the well. This could result in additional groundwater contamination if the Commission is allowing companies to create potential conduits for groundwater contamination before it ensures the companies or the Commission have sufficient funds available to prevent groundwater contamination. The financial assurance requirements under §3.78 of this title, relating to Fees and Financial Security Requirements, are insufficient to ensure that the well owners or the Commission will have enough funds on hand to plug the wells.

The Commission disagrees. The purpose of a stratigraphic test well is to obtain data concerning the formations through which the well is drilled. This data will be used in modeling the area of review for the Class VI injection well. The stratigraphic test well may then be plugged, converted to a monitor well, or converted to a Class VI injection well (if construction of the well meets the requirements for a Class VI well). The operator is required to maintain financial assurance for the well under §3.78 of this title. If the well will be plugged, the Commission will require that the well be properly plugged before injection begins. If the well is converted to a Class VI injection well, the Commission will require financial assurance under Chapter 5 to ensure that the Class VI well is plugged upon closure of the geologic storage facility.

Mr. Patrick A. Nye and Mr. Payton Campbell asked whether the logging, coring, and pressure testing will be standardized for stratigraphic test wells and for all new wells drilled within the AOR. They also asked that the definition of stratigraphic test well include injectivity testing of injection zone and 3-D seismic.

The Commission declines to make changes in response to these comments. The purpose of a stratigraphic test well is to obtain information on the characteristics of the zones through which the well is drilled, including most specifically, the proposed injection zone and confining zone(s). The rules in Subchapter B relate to requirements for Class VI injection wells, not the logging, coring, and pressure testing of stratigraphic test wells.

The Environmental Defense Fund (EDF) commented that it is generally supportive of this rulemaking and offered the following recommendation. Proposed §5.201(i) states that, "If a provision of this subchapter conflicts with any provision or term of a Commission order or permit, the provision of such order or permit controls." This language raises a question of whether the Commission orders and permits in conflict with the rules satisfy minimum federal requirements. EDF recommended that the Commission add language to §5.201(i) to clarify that Commission orders and permits in conflict with the subchapter will control "provided that the provision satisfies EPA's minimum requirements for Class VI programs." EDF commented that this change is necessary for Texas to meet EPA requirements and is consistent with the intent of the rulemaking.

The Commission agrees with this comment adopts §5.201(i) with the recommended change.

§5.202

The Texas-based Organizations recommended that §5.202(e)(2) be revised to require that the fact sheet include a description of the Commission's Environmental Justice analysis considering the presence of existing environmental hazards, cumulative impacts, potential exposure pathways, and susceptible sub-populations, as well as the likely distribution of any environmental and public health benefits from the proposed Class VI project in affected communities. The Organizations recommended that the director identify in the fact sheet whether the project at the proposed location may create any new risks or exacerbate any existing impacts on lower income people and communities of color, and list actions that the facility will be required to take to mitigate existing risks and potential new risks.

The Commission did not propose amendments to §5.202; therefore, this comment is beyond the scope of this rulemaking. Although the Commission did not make changes in response to these comments, the Commission will consider these comments in developing the Memorandum of Agreement with EPA and during program implementation.

§5.203

TCC and TXOGA expressed support for the numerous revisions to the permit application provisions in §5.203 to incorporate additional consistency with the federal regulations for Class VI permit applications. TCC and TXOGA appreciate the coordination between EPA and the Commission to create a robust regulatory scheme.

The Commission appreciates these comments.

The Texas-based Organizations recommended that the Commission revise the rule to include a process that defines how users of an underground source of drinking water will be notified if the USDW has potentially been contaminated.

The Commission declines to make the requested change because Texas already has such a procedure in place. The Texas Water Code requires that the Railroad Commission report to the Texas Commission on

Environmental Quality (TCEQ) all documented groundwater contamination. The Water Code defines contamination of groundwater as "the detrimental alteration of the naturally occurring physical, thermal, chemical, or biological quality of groundwater." Effective September 1, 2003, the Water Code also requires the TCEQ to send notification of documented groundwater contamination to the owner of a private drinking water well that may be affected by the contamination and to each applicable groundwater conservation district. Rule §601.10, Form and Content of Groundwater Contamination Notice, as adopted by the Texas Groundwater Protection Committee (TGPC), details the information required in the notice. The TCEQ must send the notice within 30 days of the date they receive knowledge of the documented groundwater contamination case.

The Texas-based Organizations recommended that the Commission revise §5.203(b) to require that the surface map and information include maps and tables of all census block groups that intersect the area of review showing the number and percentage of lower-income people, communities of color, susceptible sub-populations, and environmental and social stressors. The Organizations further recommended that the Commission revise §5.203(j), relating to Plan for monitoring, sampling, and testing after initiation of operation, to require that the plan for monitoring, sampling, and testing after initiation of operation require operators to submit revised maps and tables every five years of all census block groups that intersect the AOR, showing the number and percentage of lower-income people, communities of color, susceptible sub-populations; and environmental and social stressors. The Organizations further recommended that the Commission require that the plan include mitigation measures the operator will take if it creates any new risks or exacerbates any existing impacts on lower-income people and communities of color.

The proposed amendments in this rulemaking are very limited and the Commission did not propose to amend §5.203(b). Therefore, the comment is beyond the scope of this rulemaking. Although the Commission did not make changes in response to these comments, the Commission will consider these comments in developing the Memorandum of Agreement with EPA and during program implementation.

Mr. Patrick A. Nye and Mr. Payton Campbell requested an explanation of the modeling of the area of review, the carbon dioxide plume, and the pressure front and whether the rules for modeling will be standardized or if the Commission rely on the information provided by the operator.

The Commission points the commenters to §5.203(d)(1)(A), which describes the requirements for modeling of the area of review. The applicant must use computational modeling that considers the volumes and/or mass and the physical and chemical properties of the injected CO_2 stream, the physical properties of the formation into which the CO_2 stream is to be injected, and available data including data available from logging, testing, or operation of wells. The applicant must predict the lateral and vertical extent of migration for the CO_2 plume and formation fluids and the pressure differentials required to cause movement of injected fluids or formation fluids into a USDW in the subsurface. The model must: be based on geologic and reservoir engineering information collected to characterize the injection zone and the confining zone; be based on anticipated operating data, including injection pressures, rates, temperatures, and total volumes and/or mass over the proposed duration of injection; take into account relevant geologic heterogeneities and data quality and their possible impact on model predictions; consider the physical and chemical properties of injected and formation fluids; and consider potential migration through known faults, fractures, and artificial penetrations and beyond lateral spill points. The Commission will carefully and fully review the models used by the applicants and the data that the applicant inputs into the model.

Mr. Patrick A. Nye and Mr. Payton Campbell asked whether stratigraphic test wells within the area of review will be required to have the same casing requirements as an injection well. They also asked for clarification regarding what happens if the carbon dioxide plume encounters the test well and degradation to the cement and casing occurs. Mr. Nye recommended more requirements for casing and cement in a stratigraphic test well.

The Commission notes that §5.203(d)(1)(B) requires the applicant to identify, compile, and submit a table listing all penetrations, including active, inactive, plugged, and unplugged wells and underground mines in the AOR that may penetrate the confining zone, that are known or reasonably discoverable through specialized knowledge or experience. The applicant must provide a description of each penetration's type, construction, date drilled or excavated, location, depth, and record of plugging and/or completion or closure. Section 5.203(d)(1)(C) requires that the applicant demonstrate whether each of the wells on the table of penetrations has or has not been plugged and whether each of the underground mines (if any) on the table of penetrations has or has not been closed in a manner that prevents the movement of injected fluids or displaced formation fluids that may endanger USDWs or allow the injected fluids or formation fluids to escape the permitted injection zone. The demonstration must include evidence that the materials used are compatible with the carbon dioxide stream. The applicant must perform corrective action on all wells in the AOR that are determined to need corrective action. The operator must perform corrective action using materials suitable for use with the CO_2 stream. The Commission makes no changes in response to these comments.

With respect to §5.203(d)(2)(B), Mr. Patrick A. Nye and Mr. Payton Campbell commented that the AOR should be reviewed on a more frequent basis if the limits of the area of review are exceeded, the records indicate noncompliance and/or corrective action is needed until compliance is achieved and AOR model determined to be stable.

The Commission declines to make the requested change. Consistent with the federal requirements, §5.203(d)(2)(B) requires the applicant to provide a description of the minimum fixed frequency, not to exceed five years, at which the applicant proposes to re-evaluate the area of review (AOR) during the life of the geologic storage facility, how monitoring and operational data will be used to re-evaluate the AOR, and the monitoring and operational conditions that would warrant a re-evaluation of the AOR prior to the next scheduled re-evaluation. Also consistent with the federal requirements, §5.206(g) requires that all Class VI permits include conditions that require that, at the frequency specified in the approved AOR and corrective action plan or permit, and whenever warranted by a material change in the monitoring and/or operational data or in the evaluation of the monitoring and operational data by the operator, but no less frequently than every five years, the operator of a geologic storage facility also must perform a re-evaluation of the AOR. The Commission will require more frequent re-evaluation of the AOR as necessary based on monitoring and operational data.

Ms. Cyndi L. Valdes recommended that the Commission require that the AOR be evaluated if there is a change in injection pressure, well integrity, or evidence of plume exceeding AOR modeling limits.

The Commission declines to make the requested change. Section 5.203(d)(2)(B) requires that the applicant include in the area of review and corrective action plan a description of the minimum fixed frequency, not to exceed five years, at which the applicant proposes to re-evaluate the area of review during the life of the geologic storage facility; how monitoring and operational data will be used to re-evaluate the area of review; and the monitoring and operational conditions that would warrant a re-evaluation of the area of review prior to the next scheduled re-evaluation. Section 5.206(g) states that the frequency specified in the approved AOR and corrective action plan or permit, and whenever warranted by a material change in the monitoring and/or operational data or in the evaluation of the monitoring and operational data by the operator, but no less frequently than every five years, the operator of a geologic storage facility also must perform a re-evaluation of the AOR. An increase in injection pressure could, and evidence of the plume and pressure front exceeding the modeled boundary of the area of review would, result in a requirement that the permittee reevaluate the area of review.

The Texas-based Organizations expressed support for the amendment to §5.203(d)(2)(B)(i) adding a maximum number of years at which the applicant may propose to re-evaluate the area of review and asked whether the director will have the authority to require a shorter time frame than five years for re-evaluation.

The Commission notes that the director has the authority to require reevaluation of the area of review more frequently than every five years. Section 5.206(g) requires the permittee to perform a re-evaluation of the AOR at the frequency specified in the approved AOR and corrective action plan or permit, and whenever warranted by a material change in the monitoring and/or operational data or in the evaluation of the monitoring and operational data by the operator, but no less frequently than every five years.

Mr. Van Voorhees expressed support for the amendments to §5.203(f) because they clarify that it should not matter whether the operator submits the plan before or after the Commission has granted authority to drill a well. Mr. VanVoorhees recommended that the Commission revise the language in the preamble because it is incorrect.

The Commission appreciates this comment. Section §5.203(f) concerns a plan for logging, sampling, and testing of injection wells before injection. There are two separate authorizations associated with Class VI wells: (1) authorization to drill the injection well and perform logging, sampling and testing; and (2) authorization to inject. The plan detailing how the applicant proposes to log, sample, and test the injection well must be submitted to the Commission with the application, but the actual logging, sampling, and testing of injection well is performed according to the plan after the well has been drilled and completed, but before the

Commission issues a permit to inject. With respect to the comment regarding revising the preamble, the Commission does not adopt the preamble language and so no change is necessary.

Mr. Patrick A. Nye and Mr. Payton Campbell expressed confusion with allowing the director to require further cores when once the injection well is cased then cores cannot be taken. Typically log analysis, core analysis, and formation fluid sample information is taken from an open hole and casing the well occurs immediately after.

The Commission agrees that cores must be taken before a well is cased. However, §5.203(f)(3)(B) requires the operator to take whole cores or sidewall cores representative of the injection zone and confining zone. The director may also require the operator to core formations in the borehole other than the injection zone and the confining zone. To eliminate confusion, the Commission adopts §5.203(f)(3)(B) with a change to relocate the applicable provision.

Ms. Cyndi L. Valdes recommended that the coring and logging data should be from the injection well only, not other wells.

The Commission declines to make the requested change. Section 5.203(f)(3)(B) clarifies that the operator must take whole cores or sidewall cores representative of the injection zone and confining zone and for fluid samples from the injection zone. The section further states that the director may accept data from cores and formation fluid samples from nearby wells or other data if the operator can demonstrate to the director that such data are representative of conditions at the proposed injection well. The Commission will review any such data from other wells to ensure that the data is representative of conditions at the proposed injection well. This language is consistent with the federal regulations.

The Texas-based Organizations recommended that the Commission revise §5.203(i) to require that the operating plan include measures the operator will take to prevent creating any new risks or exacerbating any existing impacts on lower-income people and communities of color, based on an evaluation that considered the presence of existing environmental hazards, cumulative impacts, potential exposure pathways, and susceptible sub-populations. The Organizations stated that this language is consistent with EPA's Memorandum of Agreement with Louisiana in the section "Considering Environmental Justice & Civil Rights Impacts on Communities."

The Commission declines to make the recommended change. The proposed amendments in this latest rulemaking are very limited and the Commission did not propose to amend §5.203(i). Therefore, the comment is beyond the scope of this rulemaking. Although the Commission did not make changes in response to these comments, the Commission will consider these comments in developing the Memorandum of Agreement with EPA and during program implementation.

Mr. Patrick A. Nye and Mr. Payton Campbell asked whether the facility supplying the carbon dioxide will be allowed to vent the carbon dioxide in the event of an injection well shutdown. They also asked when EPA would step in to address the unrestricted flow of carbon dioxide into the atmosphere.

This comment concerns the facility at which the carbon dioxide is captured, which is beyond the scope of this rulemaking and not within the Commission's jurisdiction.

Mr. Patrick A. Nye and Mr. Payton Campbell asked whether, in the event of non-compliance for wellbore integrity, the Commission will require more frequent testing until the issue is resolved.

The Commission directs the commenters to §5.203(h), which establishes the criteria for the mechanical integrity testing plan, and requires that, other than during periods of well workover in which the sealed tubing-casing annulus is of necessity disassembled for maintenance or corrective procedures, the operator maintain mechanical integrity of the injection well at all times. The operator must either repair and successfully retest or plug a well that fails a mechanical integrity test (§5.203(h)(1)(F)). In addition, following the initial annulus pressure test, the operator must continuously monitor injection pressure, rate, temperature, injected volumes and mass, and pressure on the annulus between tubing and long string casing to confirm that the injected fluids are confined to the injection zone (§5.203(h)(1)(C)).

Mr. Patrick A. Nye and Mr. Payton Campbell asked whether the Commission will require the Bureau of Economic Geology recommended 1000 feet of shale seal above the injection zone.

The Commission contacted the Gulf Coast Carbon Center at the Bureau of Economic Geology and was advised that they do not have a recommended thickness for the confining zone(s) above the injection zone. Section 5.102(13) defines "confining zone" as a geologic formation, group of formations, or part of a formation stratigraphically overlying the injection zone or zones that acts as barrier to fluid movement. The thickness of the confining zone(s) will be evaluated to determine its effectiveness. The Commission is not aware of any recommended minimum thickness for confining zones and makes no changes in response to this comment.

Mr. Patrick A. Nye and Mr. Payton Campbell requested clarification as to whether 3-D seismic will be required to limit breaching of transmissive faults.

The Commission notes that §5.203 requires an applicant to submit a descriptive report prepared by a knowledgeable person that includes an interpretation of the results of appropriate logs, surveys, sampling, and testing sufficient to determine the depth, thickness, porosity, permeability, and lithology of, and the geochemistry of any formation fluids in, all relevant geologic formations. The applicant must submit information on the geologic structure and reservoir properties of the proposed storage reservoir and overlying formations, including: (1) geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the area from the ground surface to the base of the injection zone within the AOR that indicate the general vertical and lateral limits of all USDWs within the AOR, their positions relative to the storage reservoir and the direction of water movement, where known; (2) the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of, and the geochemistry of any formation fluids in, the storage reservoir and confining zone and any other relevant geologic formations, including geology/facies changes based on field data, which may include geologic cores, outcrop data, seismic surveys, well logs, and lithologic descriptions, and the analyses of logging, sampling, and testing results used to make such determinations; (3) the location, orientation, and properties of known or suspected transmissive faults or fractures that may transect the confining zone within the AOR and a determination that such faults or fractures would not compromise containment; (4) the seismic history, including the presence and depth of seismic sources, and a determination that the seismicity would not compromise containment; and (5) geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone.

The Texas-based Organizations expressed agreement with the amendments to §5.203(j)(2)(C) requiring more frequent corrosion monitoring for the plan for monitoring, sampling, and testing after initiation of operation. The Organizations requested clarification as to whether the Commission staff will read the semi-annual reports to ensure that the facility remains in compliance and to identify any potential signs of risk for underground sources of drinking water.

The Commission plans to carefully review all required data and reports to ensure that the permittee remains in compliance with the requirements of Subchapter B and the permit conditions to identify any potential issues relating to the protection of underground sources of drinking water. The Commission makes no changes in response to this comment.

The Texas-based Organizations expressed appreciation for the clarification in many sections related to well plugging and financial assurance requirements. Regarding §5.203(k), the Organizations stated that the Texas General Land Office previously commented that the Commission should "require cement plugging for abandonment to be from bottomhole to surface consistent with Texas Class I practice." The Commission declined to do so. The Organizations stated that they are aware of several recent cases where recently plugged oil and gas wells have failed. The Organizations, Mr. Brian Hillman, Ms. Malinda Huffman, Mr. Francisco Martinez, Ms. Leslie Meyer and Ms. Meg Davis recommended that the Commission require cement plugging from the bottomhole to surface.

The Commission declines to make this change. The Commission did not propose amendments to the sections regarding well plugging; therefore, this comment is beyond the scope of this rulemaking. As stated by the commenters, a similar comment was made to the amendments proposed in 2022 and the Commission responded that neither the federal Class VI regulations nor the TCEQ Class I regulations at 30 TAC §331.46 (relating to Closure Standards) require plugging with cement from bottomhole to the surface. TCEQ regulations at 30 TAC §331.46(e) state that a well shall be plugged in a manner which will not allow the movement of fluids through the well, out of the injection zone either into or between USDWs or to the land surface. The Commission's rules in Chapter 5 require an applicant to provide a plugging plan with the application, which will be reviewed by Commission staff for adequacy. Staff will consider factors similar to those considered by the TCEQ for Class I injection wells. These factors include, but are not limited to, the type and number of plugs to be used; the placement of each plug including the elevation of the top and bottom; the type, grade, and quantity of plugging material to be used; the method of placement of the plugs; and the procedure used to plug and abandon the well.

With respect to §5.206(k)(6)(A), the Texas-based Organizations, Mr. Brian Hillman, Ms. Malinda Huffman, Mr. Francisco Martinez, Ms. Leslie Meyer and Ms. Meg Davis commented that, while the Commission require latitude and longitude coordinates of the injection well to be depicted on a survey plat, the Commission should also require that the coordinate system (i.e. NAD 27, NAD 83, or WGS 84) be clearly noted on the plat map, rather than simply used. The Organizations also recommended that the Commission require that the coordinates for the facility and any other wells or relevant features located within and around the AOR be provided in a table, indicating the coordinate system used, and the source of the coordinates noted (e.g. RRC database, physical on-site inspection, supervised mapping using satellite imagery, etc.). The Organizations recommended that the Commission amend §5.203(b) to require the applicant to provide a table of latitude and longitude coordinates of all locations they are required to show within the area of review (AOR) under subsection (b), and specify the coordinate system used.

The Commission agrees that geographic coordinates would be useful and adopts §5.203(b)(1) with changes. The Commission also adopts §5.203(k) with a change to correct an error.

The Texas-based Organizations, Mr. Brian Hillman, Ms. Malinda Huffman, Mr. Francisco Martinez, Ms. Leslie Meyer, and Ms. Meg Davis recommended that the Commission require that wells be plugged after a specific number of years of inactivity rather than the current vague incentives to plug.

The Commission declines to make the requested change. Section 5.203(k) requires that an applicant submit to the Commission with the Class VI permit application a well plugging plan, which must be approved by the Commission. Section 5.206(j) requires that the Commission include in any permit issued under Subchapter B conditions that the operator of a geologic storage facility maintain and comply with the approved well plugging plan. Section 5.206(k)(5) requires that the Commission include in any permit issued under Subchapter B a condition that states that after the director has authorized storage facility closure, the operator must plug all wells in accordance with the approved plan. The Commission will require that the well plugging plan includes reasonable deadlines for plugging of wells. In addition, §5.205(c)(2)(H)(i)(I) requires that the operator maintain financial responsibility until the director approves closure.

The Texas-based Organizations, Mr. Brian Hillman, Ms. Malinda Huffman, Mr. Francisco Martinez, Ms. Leslie Meyer, and Ms. Meg Davis commented that the post-injection storage facility care (PISC) monitoring period is vague and no minimum time period is defined. These commenters expressed concern that the Commission will allow operators to stop monitoring their facilities, even as new drilling, production, and injection activity is taking place throughout the area of review and recommended that the Commission consider how the facility's surroundings will change over long periods of time and the ways that underground sources of drinking water will be impacted. These commenters stated that it is not safe to assume that a Class VI well drilled today will always perform the way today's subsurface models predicted it would. Additionally, the commenters noted the Commission has admitted that it does not have the authority to deny drilling permits within the AOR of a Class VI well, and merely requires coordination between the operators drilling an oil or gas well and an operator of a geologic storage facility. The Organizations requested clarification as to how the Commission will ensure that operators requesting oil and gas well drilling permits within a geologic storage facility AOR have conducted meaningful coordination.

The Commission makes no changes in response to these comments. The federal regulations include a default 50-year post injection monitoring period but allow an operator to demonstrate an alternative post injection timeframe. The Commission did not adopt the default 50-year post-injection monitoring period; instead, the Commission adopted the requirement that the operator demonstrate an alternative post-injection storage facility care timeframe. The requirements for this demonstration can be found in §5.203(m). This subsection requires that the applicant submit a demonstration containing substantial evidence that the geologic storage project will no longer pose a risk of endangerment to USDWs at the end of the post-injection storage facility care timeframe. The demonstration must show the pressure differential between pre-injection and predicted post-injection pressures in the injection zone and the predicted position of the CO_2 plume and associated pressure front at closure as demonstrated in the AOR evaluation. The demonstration must also consider and document the predicted timeframe for pressure decline within the injection zone, and any other zones, such that formation fluids may not be forced into any underground sources of drinking water, and/or the timeframe for pressure decline to pre-injection pressures; the predicted rate of CO_2 plume migration within the injection zone, and the predicted timeframe for the stabilization of the CO_2 plume and associated pressure front; a description of the site-specific processes that will result in CO_2 trapping including immobilization by capillary trapping, dissolution, and mineralization at the site; the predicted rate of CO_2 trapping in the immobile capillary phase, dissolved phase, and/or mineral phase; a characterization of the confining zone(s) including a demonstration that it is free of transmissive faults, fractures, and micro-fractures and of appropriate thickness, permeability, and integrity to impede fluid (e.g., CO_2, formation fluids) movement; the presence of potential conduits for fluid movement including planned injection wells and project monitoring wells associated with the proposed geologic storage project or any other projects in proximity to the predicted/modeled, final extent of the CO_2 plume and area of elevated pressure; a description of the well construction and an assessment of the quality of plugs of all abandoned wells within the AOR; the distance between the injection zone and the nearest USDWs above and/or below the injection zone; and any additional site-specific factors required by the director.

§5.204

TCC expressed support for the Commission's revisions to §5.204, which TCC believes provide increased specificity and transparency.

The Commission appreciates this comment.

The Texas-based Organizations recommended that the Commission revise §5.204(a), relating to Notice requirements, to require that the content of notices the applicant provides include a statement that "interested and affected persons may protest the application." The Texas-based Organizations requested clarification as to whether protests may be made by both interested persons and affected persons.

The Commission notes that under §5.204(a), the Commission is the entity that provides the notice of draft permits. The Commission defines "affected person" in §5.102(1) as a person who, as a result of activity sought to be permitted has suffered or may suffer actual injury or economic damage other than as a member of the general public and defines "interested person" in §5.102(32) as any person who expresses an interest in an application, permit, or Class VI UIC well. Affected persons may protest an application. Under §5.204(b)(1)(A), any interested person may submit written comments on the draft permit during the public comment period and may request a hearing if one has not already been scheduled. Under §5.204(b)(2)(B), the director must hold a public hearing whenever the director finds, on the basis of requests, a significant degree of public interest in a draft permit. In addition, under §5.204(b)(2)(C), the director may also hold a public hearing at the director's discretion, whenever, for instance, such a hearing might clarify one or more issues involved in the permit decision. However, the Commission agrees that clarification would be helpful and has revised §5.204(a)(4)(E) to clarify that the notice must include a statement that interested persons may request a hearing on the application.

Mr. Van Voorhees recommended that the Commission substitute "EPA" for "Environmental Protection Agency" in §5.204(a)(3)(A)(ii) since the Commission has defined "EPA" in §5.102(20).

The Commission agrees with this comment and has made the recommended change.

Ms. Lana Straub commented that, in §5.204(a)(3)(A)(iv), instead of "outermost boundary" it should be changed to read "entire boundary of the proposed geologic storage facility."

The Commission disagrees. Section 5.204(a)(3)(A)(iv) requires notice to each mineral interest owner adjoining the modeled boundary of the proposed geologic storage facility. Section 5.204(a)(3)(A)(v) requires notice to each leaseholder and interest owner of minerals lying above or below the proposed geologic storage facility, meaning within the boundary of the geologic storage facility. The Commission made no change in response to this comment.

Ms. Straub also commented regarding notice requirements in §5.204(a)(3)(A)(iv)-(vi). She suggested that "all mineral interest owners, including non-participating interest owners, working interest owners, and overriding interest owners" should be listed as a party to be notified.

The Commission declines to make the requested change. The proposed amendments in this rulemaking are very limited and the Commission did not propose to amend §5.204(a)(3)(A)(iv)-(vi). Therefore, the comment is beyond the scope of this rulemaking. However, the Commission believes that notice is adequate because §5.204(a)(3)(A)(iv) – (vi) requires that the Commission give notice of a draft permit or a public hearing to each adjoining mineral interest owner, other than the applicant, of the outermost boundary of the proposed geologic storage facility; each leaseholder and interest owner of minerals lying above or below the proposed geologic storage facility; and each adjoining leaseholder of minerals offsetting the outermost boundary of the proposed geologic storage facility, along with the required publication.

The Texas-based Organizations recommended that the Commission revise §5.204(a)(4) to require that the content of notices allow for protests to applications to be emailed. Owning a printer in the home is less common than it used to be, and is less likely for low-income individuals. Mailing a letter of protest requires extra steps that may waste time for many people, especially those who live in rural areas or who do not have easy access to the post office or a printer. Additionally, post offices tend to be closed outside of normal working hours, reducing the opportunity for working people to access stamps needed to mail a letter.

The Commission declines to make the requested change because §5.204(a)(4) does not prohibit submission of protests via electronic mail.

Commission Shift requested that the Commission extend the rulemaking process to hold public hearings throughout the state of Texas in disadvantaged communities, at times when the public can attend, and in locations that are easy to access by public transportation. Commission Shift requested that these hearings discuss potential approaches to ensure that disadvantaged communities have an opportunity to meaningfully participate in permit application proceedings and that the meetings include two-way dialogue between community members and the agency.

Commission Shift also commented that environmental justice is not defined in the current draft of the rule, but operators will be expected to conduct additional outreach to environmental communities that are within a proposed facility's area of review. Commission Shift and the Texas-based Organizations recommended that the Commission include rule language that incorporates environmental justice language included in the Memorandum of Agreement between EPA and the State of Louisiana for the Class VI program. These commenters recommended that the language be specific, respond to the needs of the environmental justice communities, and consider demographic factors as they impact the ease with which these communities are able to engage.

Mr. Brian Hillman, Ms. Malinda Huffman, Mr. Francisco Martinez, Ms. Leslie Meyers, Ms. Meg Davis, and the Texas-based Organizations commented that there are several opportunities for the Commission to incorporate meaningful provisions throughout the Chapter 5 rules other than simply requiring notice to certain communities. Addressing the legacy of environmental racism and the cumulative impacts of industrial development on susceptible communities means that the Commission must require operators to plan and take actions to prevent and mitigate risks posed to these communities throughout the permit application process and during operation. These mitigation actions should be considered by the Commission before a permit is approved.

The Texas-based Organizations recommended that the Commission incorporate robust and ongoing opportunities for public participation, especially for lower-income people, communities of color and those experiencing a disproportionate burden of pollution and environmental hazards. The comment recommended that the Commission provide ample notice of proposed Class VI wells and tailor public participation to specific community needs and interests. Commission Shift commented that those living in rural areas of Texas do not have access to unlimited high-speed internet and that most people do not understand the jargon in the applications and cannot afford an attorney to help them engage successfully in a protest. Tailored public participation activities may include scheduling public meetings at times convenient for residents with appropriate translation services where needed, enabling face-to-face or written feedback on permit applications early in the review process, convening local stakeholders and community groups for safety planning, or supporting the development of community benefits agreements.

The Texas-based Organizations also recommended that the Commission include in §5.204(a) information about how to access language accommodation related to the notice in all languages that are known to be spoken in the counties related to the area of review. The Texas-based Organizations requested that the Commission require that mailed notice be sent in other relevant languages for the location, and not merely "published." The Texas-based Organizations recommended that the Commission require that applicants for Class VI permits provide written translation services upon request, not only verbal interpretation services. The Organizations also requested clarification as to whether the applicant will be responsible for coordinating and paying for translation and interpretation related to the permit application and any documents associated with a hearing. Further, the Texas-based organizations asked that the Commission require that qualified interpreters who are familiar with the relevant technical jargon be used to provide interpretation and translation.

The Commission declines to make these recommended changes. The proposed amendments in this rulemaking are very limited and the Commission did not propose to amend the language that is the subject of these comments. Therefore, the comments are beyond the scope of this rulemaking. The federal process for granting primacy requires that EPA hold a public hearing on EPA's determination regarding state primacy. This hearing will provide the public with an opportunity to provide comment on the entirety of the Commission's regulations and implementation plans. Although the Commission did not make changes in response to these comments, the Commission will consider these comments in developing the Memorandum of Agreement with EPA and during program implementation.

Mr. McCown urged the Commission to provide directions for making a comment in Spanish, and to make the proposed rule amendments available in Spanish.

The Commission plans to make a summary of rules available in Spanish in the near future.

The Texas-based Organizations recommended that the Commission revise the language in §5.204(a)(6), relating to Notice to certain communities, to read as follows: "The applicant shall identify whether any portions of the AOR encompass an Environmental Justice (EJ) or Limited English-Speaking Household community populations that are lower income, communities of color, households with non-English language needs, or other susceptible subpopulations identified using the EPA's EJSCREEN most recent U.S. Census Bureau American

Community Survey data or other tools including but not limited to those recommended in the most up-to-date versions of EPA-published environmental justice guidance documents. If the AOR includes populations that are lower income, communities of color, households with language access needs, or other susceptible subpopulations an EJ or Limited English-Speaking Household community, the applicant shall conduct enhanced public outreach activities to these communities." The Texas-based Organizations also recommended that the Commission require that EPA's EJSCREEN be used to identify environmental and social stressors in specific communities, as well as to allow other tools to be used to calculate impacts to communities, including but not limited to the most up-to-date versions of EPA-published EJ guidance documents.

The Commission declines to make the requested changes. As mentioned above, the proposed amendments in this rulemaking are limited and the comment is beyond the scope of this rulemaking. EPA's EJ tool is periodically revised and can be referenced in the Memorandum of Agreement as an additional evaluation tool to assist in forming a plan for environmental justice on project sites and during program implementation. Although the Commission does not make changes in response to these comments, the Commission will consider these comments in developing the Memorandum of Agreement with EPA and during program implementation.

The Texas-based organizations, Mr. Brian Hillman, Ms. Malinda Huffman, Mr. Francisco Martinez, Ms. Leslie Meyer, and Ms. Meg Davis recommended that the Commission consider an alternative metric than "limited English-speaking households" to determine the presence of language accommodation needs in the AOR. The commenters believe the current definition of limited-English speaking households would fail to ensure language accommodation where it is needed, and create situations where children are expected to translate and interpret technical jargon for their households. The Texas-based Organization commented that, in §5.102, relating to Definitions, the Commission defines a limited English-speaking household as "a household in which all members 14 years and older have at least some difficulty with English," adopting a definition used by the U.S. Census Bureau. The Organizations expressed concern that using this definition may fail to capture communities that need interpretation and translation services. For example, in many bilingual families, children under the age of 18 are the only English-speaking members in their household. It is unreasonable to assume that a child would be a sufficient translator for their parents or guardians to be able to understand a Class VI permit application notice. However, using the definition the Commission has chosen, households that have a single member aged 14 or older who can speak English very well may not be counted as a limited English-speaking Census Bureau. Specifically, the 1-year American Community Survey (ACS) data is often incomplete, and data is null in many counties for the 2021 1-year ACS, including Webb County where more than 95% of the population is Hispanic and limited English-speaking households are common. The 5-year ACS data includes more counties and should be considered as the more complete and comprehensive dataset by which an assessment is made.

The Texas-based Organizations also recommended that the Commission adopt Limited English Proficiency (LEP) assessment guidelines aligned with those adopted by the Texas Commission on

Environmental Quality (TCEQ). TCEQ has adopted Alternative Language Requirements in Title 30 of the Texas Administrative Code, Chapter 39, Subchapter H, Rule §39.426 for providing notice to LEP communities.

The Commission declines to make the requested changes because they are outside the scope of this rulemaking. The Commission will consider these comments in developing the Memorandum of Agreement with EPA and during program implementation.

Regarding §5.204(b), the Texas-based Organizations requested information as to the number of times an applicant may revise the application if the director determines that the director cannot approve an application as written.

The Commission directs the commenters to §1.201, relating to Time Periods for Processing Applications and Issuing Permits Administratively. Section 1.201 outlines the requirements for supplemental filings for applications. Though §1.201 currently applies only to the permits listed in the rule, the Commission plans to amend §1.201 in the future to include the permits issued under Subchapter B. In the meantime, the director will determine when an applicant has reached its maximum number of revisions such that the application will be denied.

With respect to §5.204(b)(2), the Texas-based Organizations recommended that the Commission require that public hearings be held in the same county where the facility is to be located; at times outside of normal working hours to allow for working people to attend; and online allowing for public comment from interested persons who may be unable to attend in person.

The Commission did not propose revisions to §5.204(b)(2) and, therefore, the comment is beyond the scope of the rulemaking. The Commission will consider these comments in developing the Memorandum of Agreement with EPA and during program implementation. The Commission is able to hold hearings live or virtually, or both.

The Texas-based Organizations asked whether the Commission will provide any financial assistance to protestants from low income communities during the hearing process and asked how the Commission will ensure that low income protestants have a fair opportunity to participate and hire experts to help argue their side in a hearing.

The Commission has no statutory authority to provide financial assistance to protestants.

With respect to §5.204(b)(3), the Texas-based Organizations commented that the rules allow the director to administratively approve an application if it receives no protest on the application. The Organizations requested clarification as to whether the administrative approval includes a critical review of whether the information presented in the application is true and to what extent the Commission will verify that the facility plans and design are in compliance with Commission rules if there are no protests.

The Commission notes that the director may only issue a permit after the director finds that the applicant has satisfied all of the criteria required by §5.206(b), which includes that freshwater will be protected, that the injection of anthropogenic carbon dioxide will not endanger or injure human health and safety, that the applicant has demonstrated financial responsibility and has submitted financial assurance necessary to perform post-injection monitoring and closure of the facility. Each permit application for a geologic storage facility will be reviewed by staff with technical expertise for completeness and technical requirements before a permit or permit denial is issued as described in the Commission's Class VI UIC Program Description, a draft of which is available on the Commission's website.

Regarding the Commission's proposed revisions to §5.204(b)(5), TXOGA commented that the amendments are consistent with 40 CFR §124.17 and provide increased specificity for how the response to comments will be made public. TXOGA expressed support for these revisions and the Commission's commitment to transparency in the permitting process.

The Commission appreciates this comment.

The Texas-based Organizations recommended that the Commission list some of the information that it needs to receive from persons who are protesting the application. For example: name, phone number, address, reason for protesting, and any other information the Commission would need when receiving and recording a protest.

The Commission is the entity that develops and provides the notice of an application and of a public hearing. The Commission will consider these comments when drafting the notices of draft permits and public hearings. The Commission makes no change in response to this comment.

§5.205

TCC and TXOGA expressed support for the proposed amendments to §5.205 with respect to financial assurance requirements. The Texas-based Organizations expressed appreciation of the many helpful additions and clarifications that were made to strengthen financial assurance requirements.

The Commission appreciates these comments.

TXOGA commented that §5.205(c)(2)(A)(i) states that the cost estimate used for site closure should include plugging all wells (e.g., monitoring wells) that may never be drilled. The corresponding EPA regulation only discusses the injection wells when determining the closure cost estimate. TXOGA proposes that the Commission adopt EPA's language or include a mechanism to address the financial assurance associated with these other well types.

Further, TXOGA commented that §5.205(c)(2)(A)(i) contemplates the use of a "written estimate of the highest likely dollar amount necessary" as the basis for financial assurance. This language is more stringent than the federal regulations at 40 CFR §146.85(c), which require "a detailed written estimate, in current dollars, of the cost of performing corrective action on wells in the area of review, plugging the injection well(s), post-injection site care and site closure, and emergency and remedial response." TXOGA recommended that the Commission defer to EPA language, which ensures sufficient financial assurance for closure and post-closure scenarios and is updated annually.

The Commission agrees and adopts §5.205(c)(2)(A)(i) with a change to address the comment.

TXOGA also commented that under the Commission's proposed regulations, it is unclear when financial assurance must be provided. The Commission's proposal alludes to providing financial assurance both prior to carbon dioxide injection (§5.205(c)(2)(B)) and prior to permit issuance (§5.205(c)(2)(A)(ii)). TXOGA believes the requirement should be prior to carbon dioxide injection only.

The Commission notes that §5.205(c)(2)(B) states that a geologic storage facility shall not receive CO_2 until a bond or letter of credit in an amount approved by the director and meeting the requirements of the subsection as to form and issuer has been filed with and approved by the director. Financial assurance is required before the Commission issues the permit to inject.

Mr. Robert Van Voorhees commented that the Commission's regulations use both "financial responsibility" and "financial assurance," which could potentially lead to some confusion. Mr. Van Voorhees noted that both terms are also used interchangeably in the EPA promulgated Class VI regulations. If the Commission intends these terms to have different meanings, Mr. Van Voorhees requested clarification as to the meanings and requested that the Commission check for consistency in use.

The Commission agrees that the federal rules use the terms "financial responsibility" and "financial assurance" interchangeably. The Commission rules reflect the use of the terms as used in the federal regulations. The Commission made no change in response to this comment.

Mr. Patrick A. Nye and Mr. Payton Campbell requested clarification regarding how additional Commission personnel is justified when a third-party delegate is required to evaluate the financial requirements of the permit.

The Commission makes no changes in response to this comment. Section 5.205(c)(2)(C)(i) states that the cost estimate for closure of the geologic storage facility must be performed for each phase separately and must be based on the costs to the Commission of hiring a third party to perform the required activities. The section does not require the Commission to hire a third party to develop the estimate but, rather, requires that the cost estimate be based on the costs to the Commission to hire a third party to perform the required activities.

TCC and TXOGA commented that the Commission's regulations do not specify the financial assurance instruments that qualify under the regulations as satisfactorily demonstrating financial assurance. EPA regulations at 40 CFR §146.85 list which financial instruments must be used: trust funds; surety bonds; letter of credit; insurance; self-insurance (i.e., Financial Test and Corporate Guarantee); escrow account; and any other instrument(s) satisfactory to the Director. While §5.205(c)(2)(D) states that bonds "and letters of credit filed in satisfaction of the financial assurance requirements for a geologic storage facility must comply with the following standards as to issuer and form," this does not clarify if bonds and letters of credit are the only sufficient instruments to demonstrate financial assurance.

TXOGA does not believe, as has been suggested, that Texas lacks statutory authority to authorize the use of financial assurance mechanisms other than letters of credit and bonds. Chapter 27 of the Texas Water

Code grants the Commission ample statutory authority to allow for various forms of financial security for Class VI injection wells. Such financial assurance forms can include insurance, self-insurance, or escrow as well as bonds and letters of credit. The Commission need only adopt rules enumerating these additional acceptable forms of assurance and setting parameters for their use. This is directly supported by the plain language of Texas Water Code §27.073, Financial Responsibility. Further, TXOGA notes that other agencies have not chosen to limit the forms of financial security that can be used for Class VI injection wells. For instance, EPA's financial assurance rule provides that an "owner or operator shall demonstrate and maintain financial responsibility for post-closure by using a trust fund, surety bond, letter of credit, financial test, insurance or corporate guarantee that meets the specifications for the mechanisms and instruments revised as appropriate to cover closure and post-closure care . . ." 40 C.F.R. § 146.73. The Commission must adopt rules consistent with those of EPA. Including insurance and corporate guarantees among the available financial assurance mechanisms would be consistent. Ample statutory authority supports the Commission's ability to promulgate rules that include insurance and corporate guarantees among the suite of financial assurance options for Class VI wells.

TIP endorsed the comments submitted by TXOGA regarding the proposed amendments and urged the Commission to give those comments serious consideration, particularly as they relate to the Commission's existing statutory authority under Chapter 27 of the Texas Water Code to authorize Class VI applicants to employ the full suite of financial assurance mechanisms contemplated in 40 CFR 146.73.

The Commission notes that both EPA's and the Commission's rules require that operators maintain financial assurance for activities related to operating, maintaining, monitoring, and closing geologic storage facilities. The Commission's regulations currently allow surety bonds and letters of credit. In addition to surety bonds and letters of credit, the federal regulations allow for trust funds, insurance, self-insurance (i.e., financial test and corporate guarantee), and escrow accounts. The Commission declines to make the requested change for several reasons. First, the Commission believes a revision to allow additional forms of financial responsibility would be material such that republication of §5.205 would be required to allow public comment. In addition, some financial responsibility mechanisms may involve an acceptable level of financial risk to the state, while others may expose the state to more risk than the regulating agencies deem prudent. The Commission has not evaluated the various potential additional forms of financial responsibility in terms of the nature and extent of the risk to the state.

Mr. Van Voorhees recommended that the Commission revise §5.205(c)(2)(H) to substitute "issues a certificate of closure" for "approves storage facility closure" to eliminate an inconsistency and potential cause of confusion as to when exactly the Commission will release operators from the requirement to maintain financial responsibility and assurance.

The Commission agrees and adopts §5.205(c)(2)(H) with the recommended change.

Mr. Patrick A. Nye and Mr. Payton Campbell asked whether there will be sufficient liability insurance for private or public property damages.

The Commission does not have the authority under Texas law to require insurance for property damage.

§5.206

In §5.206, relating to Permit Standards, TCC and TXOGA expressed support for the proposal requiring that "within 30 days after the completion or conversion of an injection well subject to this subchapter, the operator must file with the division a complete record of the well on Commission Form W-2, Oil Well Potential Test, Completion or Recompletion Report and Log showing the current completion" as opposed to "the appropriate form."

The Commission appreciates these comments.

The Texas-based Organizations recommended that the Commission revise §5.206(b) to include the following in the list of criteria that allows the director to issue a permit: "The siting of a Class VI project at the proposed location does not have the potential to create any new risks or exacerbate any existing impacts on lower-income people and communities of color, based on an evaluation that considered the presence of existing environmental hazards, cumulative impacts, potential exposure pathways, and susceptible sub-populations." This language is consistent with the EPA's MOA with Louisiana in the section "Considering Environmental Justice & Civil Rights Impacts on Communities."

The Commission declines to make the requested change. The proposed amendments in this rulemaking are limited and this comment is beyond the scope of the rulemaking. The Commission will consider these comments in developing the Memorandum of Agreement with EPA and during program implementation.

In §5.206(c)(2), TCC and TXOGA expressed appreciation for the additional specificity and clarity provided in the regulation.

The Commission appreciates these comments.

TCC and TXOGA highlighted a potential drafting error in §5.206(d)(1)(B)(ii). The Commission proposes that prior to approval for the operation of a Class VI injection well, the operator shall submit and the director shall consider "any relevant updates, based on data obtained during logging and testing of the well and the formation as required by §5.203(f) of this title, to the information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, submitted to satisfy the requirements of clauses (iii), (iv), (v), (vii), and (x) of this subparagraph." This appears to be a drafting mistake, both in the reference to §5.203(f) and the references to the subsections (iii), (iv), (v), (vi), (vii), and (x). Federal regulations at 40 CFR §146.82(c)(2) require consideration of any relevant updates, based on data obtained during logging and testing of the well and the formation as required by paragraphs (c)(3), (4), (6), (7), and (10), or correspondingly for the Commission's regulations §5.206(d)(1)(B)(iii), (iv), (vi), (vii), and (x). To comply with federal regulations, the Commission may have switched the references in this provision, and it appears the Commission may be referring to incorrect subsections in its references. TXOGA encourages the Commission to further review this section and provide clarity on the requirements.

The Commission agrees and adopts §5.206(d)(1)(B)(i) and (ii) with a change to address the comments.

EPA recommended that §5.206(e) and (m) be revised to provide a reference to the plugging and abandonment procedures under 40 CFR §144.52(a)(6) or under Part 146 subpart G as appropriate.

The Commission notes that Part 146 subpart G is applicable to Class I hazardous waste injection wells. Section 144.52(a), relating to Establishing permit conditions, states that permits "for owners or operators of Class VI injection wells shall include conditions meeting the requirements of subpart H of part 146. Permits for other wells shall contain the following requirements, when applicable." Therefore, §144.52(a)(6) is not applicable to Class VI injection wells. In addition, §144.52(a)(6) references the Regional Administrator, which implies that the paragraph applies to permits issued by EPA. However, the Commission adopts §5.206(e)(5)(B)(ii) and (m)(1)(B) with changes to provide a reference to the plugging and abandonment plan in §5.203(k)(2) for the injection wells.

Mr. Patrick A. Nye recommended that the Commission not strike the language in §5.206(f)(3) which states that the operator must either repair and successfully retest or plug a well that fails a mechanical integrity test.

The Commission agrees with this comment. Section 5.203(h) states that an operator must either repair and successfully retest or plug a well that fails a mechanical integrity test. The Commission adopts §5.206(f) with a change to include this language as recommended.

With respect to §5.206(f)(4), the Texas-based Organizations, Mr. Brian Hillman, Ms. Malinda Huffman, Mr. Francisco Martinez, Ms. Leslie Meyer, and Ms. Meg Davis commented that this new section allows continued operation of a well even if a mechanical integrity test fails, regardless of whether any repair or retest has taken place. This poses a threat to people living nearby or depending on the water supplies in the area. Requiring repair after a well fails mechanical integrity testing is a necessary step in preventing groundwater contamination. Mr. Patrick A. Nye and Mr. Payton Campbell commented that loss of internal mechanical integrity could result in a multitude of issues for the injection well and could increase the risk to groundwater and public safety. Instead of allowing continuing injection at the discretion of the director, these commenters recommended that the Commission assemble a team to determine the risks before continuing injection.

The Commission notes that under 40 CFR §146.8(a) and §5.102(36), an injection well has mechanical integrity if: (1) there is no significant leak in the casing, tubing or packer; and (2) there is no significant fluid movement into an underground source of drinking water through vertical channels adjacent to the injection well bore. Consistent with the federal regulations at 40 CFR §144.51(q)(3), the Commission's regulations at §5.206(f)(4) state that the director may allow the operator of a well which lacks mechanical integrity to continue or resume injection if the operator has made a satisfactory demonstration that there is no movement of fluid into or between underground sources of drinking water. However, the Commission adopts §5.206 with a change to clarify that the director may only consider allowing the operator of a well which lacks mechanical integrity to continue or resume injection if the operator has made a satisfactory demonstration that there is no movement of fluid into or between underground sources of drinking water, and the reason for the lack of mechanical integrity is a leak in the casing, tubing, or packer.

Mr. Patrick Nye recommended that the Commission revise §5.206(f)(4) to require at least monthly monitoring of the well, area of review, and movement of the injection fluid.

The Commission declines to make the suggested change. Section 5.206(f)(4) states that the director may allow the operator of a well which lacks internal mechanical integrity to continue or resume injection if the operator has made a satisfactory demonstration that there is no movement of fluid into or between underground sources of drinking water. Section 5.203(h)(1)(C) requires that following an initial annulus pressure test, the operator must continuously monitor injection pressure, rate, temperature, injected volumes and mass, and pressure on the annulus between tubing and long string casing to confirm that the injected fluids are confined to the injection zone.

Mr. Patrick A. Nye and Mr. Payton Campbell requested clarification of required actions if the carbon dioxide plume and/or pressure front extends beyond the area of review and there are unplugged wells in the area and whether penalties would be assessed.

The Commission adopts §5.206(g) with a change to remove repetitive language that may have caused confusion.

EPA commented that there should be an "and" between §5.206(h)(3) and (4) to make it consistent with §146.84, relating to Area of review and corrective action.

The Commission disagrees. The Commission's regulations in §5.206(h)(1) through (4) are the same as the federal regulations in 40 CFR §146.84(e)(1) through (4), but the Commission's regulations add 5.206(h)(5) and place the "and" between paragraphs (4) and (5).

The Texas-based Organizations commented that they believe that many operators may be taking advantage of the Commission's weak oversight structures and may be disregarding failing tests until they are able to conduct a test that somehow passes (§5.203(j)(2)(F)). The Organizations recommended that the Commission consider conducting these tests itself or requiring independent third parties to conduct the tests. In addition, the Organizations recommended that the Commission consider allowing a landowner, or a qualified representative the landowner appoints, to witness the mechanical integrity test.

The Commission disagrees. Section 5.206(i) requires that the Commission include in any permit issued under Subchapter B conditions that require the permittee to provide the division with the opportunity to witness all planned well workovers, stimulation activities, other than stimulation for formation testing, and testing and logging. This subsection further requires that the condition must require the permittee to submit a proposed schedule of such activities to the Commission at least 30 days prior to conducting the first such activity and submit notice at least 48 hours in advance of any actual activity. The Commission plans to witness all such tests.

TCC and TXOGA commented that they support the Commission's proposed change in §5.206(k)(5) because it demonstrates consistency throughout the Commission's regulations.

The Commission appreciates these comments.

Mr. Van Voorhees recommended that the Commission replace the phrase "United States Environmental Protection Agency" with "EPA" in §5.206(k)(6)(A).

The Commission agrees with this comment and adopts §5.206(k)(6)(A) with the recommended change.

EPA commented that the state regulations do not identify the specific types of records to be kept. Mr. Patrick A. Nye and Mr. Payton Campbell requested that the record retention period be 10 years rather than three years, and that the period be extended if there are noncompliance or integrity issues. These commenters also requested clarification on whether the records would be made public.

TXOGA commented that there are conflicting record retention timing requirements within the permit standards (§5.206) and recordkeeping and reporting (§5.207) sections for injected fluids and testing and monitoring data.

The Commission adopts §5.206 with changes to address these comments and to ensure consistency with 40 CFR §144.52(j). The Commission adopts §5.206(m) with a change to require that a permittee retain: all modeling inputs and data used to support area of review reevaluations for 10 years; all data collected for Class VI permit applications throughout the life of the geologic storage project and for 10 years following site closure; data on the nature and composition of all injected fluids until 10 years after site closure; monitoring data for 10 years after it is collected; and well plugging reports, post-injection site care data, including data and information used to develop the demonstration of the alternative post-injection site care timeframe, and the site closure report for 10 years following site closure. The director has authority to require the operator to retain any records required in this subchapter for longer than 10 years after site closure.

The Commission also adopts §5.207(b)(2) with a change to correct an error.

Regarding §5.206(o)(2)(M)(iii), TXOGA recommended that the Commission clarify that entities under common control would not be considered a permit transfer.

The Commission disagrees. The federal requirement in 40 CFR §144.51(l)(3) states that the Commission must include a condition in any Class VI permit that this "permit is not transferable to any person except after notice to the Director. The Director may require modification or revocation and reissuance of the permit to change the name of the permittee and incorporate such other requirements as may be necessary under the Safe Drinking Water Act." The federal regulations at 40 CFR 144.3 define "person" as "an individual, association, partnership, corporation, municipality, State, Federal, or Tribal agency, or an agency or employee thereof." The Commission's rule in §5.201(42) defines "person" as a "natural person, corporation, organization, government, governmental subdivision or agency, business trust, estate, trust, partnership, association, or any other legal entity." The Commission believes that a transfer is required because the entities under common control would still be separate legal entities. The Commission makes no change in response to this comment.

Mr. Payton Campbell recommended that any physical alterations be reported immediately to ensure protection of the public and freshwater supply. Mr. Campbell also asked whether there are penalties for noncompliance. Mr. Patrick A. Nye recommended that the Commission revise §5.206(o)(2)(M)(i) to require a definitive time to report any planned physical alterations or additions to the permitted facility.

The Commission makes no changes in response to these comments. Section 5.206(o)(2)(M)(i) requires that the permittee give notice to the director as soon as possible of any planned physical alterations or additions to the permitted facility. This requirement is consistent with the federal regulations in 40 CFR §144.51(l)(1). The Commission has the authority to pursue enforcement action, including penalties, for noncompliance with this permit condition.

Mr. Patrick A. Nye recommended that the Commission revise §5.206(o)(2)(M)(vi) regarding twenty-four hour notice of any noncompliance which may endanger health or the environment to include monetary penalties for non-compliance.

This comment is beyond the scope of this rulemaking. Section 5.208 states that an operator that violates this subchapter may be subject to penalties and remedies specified in the Texas Natural Resources Code, Title 3 Texas Water Code, Chapter 27, and other statutes administered by the Commission. The Commission did not propose amendments to §5.208.

Ms. Straub recommended that in §5.206, the Commission add "the injection and geologic storage shall be confined to its zone of injection."

The Commission does not agree the recommended change is necessary. Under §5.206(b)(5), the director may issue a permit if the applicant demonstrates and the director finds that the reservoir into which the carbon dioxide is injected is suitable for or capable of being made suitable for protecting against the escape or migration of carbon dioxide from the storage reservoir. The conditions of any permit issued under Subchapter B will specify where injection is permitted (including an injection interval and/or zone). Any injection contrary to the permit would not be authorized and such injection would be an enforceable violation. In addition, §5.102(d)(2)(B)(i)(III) states that fluids escaping or are likely to escape from the injection zone may be a cause to terminate a permit during its term or deny a permit renewal application. The Commission makes no change in response to this comment.

§5.207

The Texas-based Organizations expressed appreciation of the additional requirements added to §5.207, relating to Reporting and Record-Keeping.

The Commission appreciates this comment.

TCC and TXOGA commented that the Commission proposes in §5.207(a)(2)(A) that certain reports for specific issues be reported within 24 hours of discovery. The proposed provision also requires that the information be reported in writing within five working days of discovery and that the written submission contain "a description of the noncompliance and its cause, the period of noncompliance, including exact dates and times and, if the noncompliance has not been corrected, the anticipated time it is expected to continue, and steps taken or planned to reduce, eliminate, and prevent reoccurrence of the noncompliance." TCC and TXOGA commented that federal regulations at 40 CFR §146.91 do not include a similar requirement. TCC and TXOGA believe the written reporting requirement is unduly burdensome and that reporting the issues listed above within 24 hours of discovery should be sufficient for the purposes of notice under the regulation. Both commenters recommended that this condition to report such findings within five working days be removed.

The Commission makes no change in response to these comments because federal regulations at 40 CFR §144.51(l)(6)(ii) require the written submission within 5 days of the time the permittee becomes aware of circumstances. The federal regulations also require that the written submission contain a description of the noncompliance and its cause, the period of noncompliance, including exact dates and times, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent reoccurrence of the noncompliance.

TCC and TXOGA commented that the Commission is proposing in §5.207(a)(2)(D)(vi) that annual reports must include "other information as required by the permit." They commented that this requirement is unnecessarily vague and may make compliance with the regulation difficult. TCC and TXOGA recommended that the Commission clearly identify and list any requirement that must be included within an annual report.

The Commission makes no change in response to these comments. The reporting requirements in §5.207(a) are minimum reporting requirements. The Commission may include as a permit condition a requirement that the permittee report certain information that is not otherwise listed in §5.207(a)(2)(D). At this time, the Commission is not certain what that information might include.

Mr. Van Voorhees recommended that the Commission substitute "EPA" for "Environmental Protection Agency" in §5.207(b)(2) since the Commission has defined "EPA" in §5.102(20).

The Commission agrees with this comment and adopts §5.207(b)(2) with the recommended change.

With respect to §5.207(e), Mr. Patrick A. Nye commented that the Commission should require all records to be sent to the Commission and that the records should be made available for public use.

The Commission notes that the rule requires that records be sent to the Commission consistent with federal requirements. These records will be available to the public.

EPA commented that the state regulations must include a requirement to retain data collected to prepare the permit application. Title 40 CFR §146.91(f)(1) requires all data collected for Class VI permit applications to be retained throughout the life of the project and for 10 years following site closure.

The Commission points EPA to §5.207(e)(1), which states, "The operator must retain all data collected under §5.203 of this title for Class VI permit applications throughout the life of the geologic sequestration project and for 10 years following storage facility closure.

TCC expressed concern with the requirement in §5.207(e)(3) to retain all testing and monitoring data collected pursuant to the plans required under §5.203(j) for at least 10 years after the data is collected. TCC noted this requirement is inconsistent with federal regulations, which only require that monitoring data be retained.

The Commission makes no change in response to this comment. Section 5.207(e)(3) corresponds to the federal regulations at §146.92(f)(3), which require that the operator of a Class VI well retain monitoring data pursuant to §146.90(b) through (i) for 10 years after it is collected. Section §146.90(b) through (i), corresponds to §5.203(j)(2) and, although both reference monitoring data, both include testing as well as monitoring data (e.g., external mechanical integrity testing and pressure falloff testing).

TXOGA expressed concern with the Commission's proposal in §5.207(e)(4) that an operator must retain "data and information used to develop the demonstration of the alternative postinjection storage facility care timeframe, and the closure report collected pursuant to the requirements of §5.206(k)(6) and (m) of this title for 10 years following storage facility closure." TXOGA commented that the federal regulations at 40 CFR §146.91(f)(4) require an operator to retain such data and information for 10 years "if appropriate." As "data and information used to develop the demonstration of the alternative post-injection storage facility care timeframe and the closure report collected pursuant to the requirements of §5.206(k)(6) and (m)" may not always be collected for each facility, TXOGA recommended that the Commission require the retention of this information only "if appropriate" for the facility.

The Commission makes no change in response to this comment. The federal regulations include a default 50-year post injection monitoring period but allow an operator to demonstrate an alternative post injection timeframe. The Commission did not adopt the default 50-year post-injection monitoring period; instead, the Commission adopted the requirement that the operator demonstrate an alternative post-injection storage facility care timeframe. Therefore, retention of these records will be required for each facility permitted in Texas.

The remainder of the proposed language is adopted without changes. Those amendments are summarized as follows.

Amendments to §5.102

The Commission amends §5.102(2) regarding the definition of "Anthropogenic carbon dioxide (CO_2)" to reflect that the term includes all carbon dioxide that has been captured from, or would otherwise have been released into, the atmosphere. The adopted change clarifies that the regulations apply to carbon dioxide resulting from direct air capture technologies. A corresponding change is also adopted in the definition of "carbon dioxide (CO_2) stream" in §5.102(7).

The Commission amends the definition of "anthropogenic CO_2 injection well" in §5.102(3) and the definition of "geologic storage" in §5.102(28) to clarify that the regulations apply to the various phases of carbon dioxide (gaseous, liquid, or supercritical) for consistency with the federal Class VI UIC regulations.

The Commission adds new paragraph (20) in §5.102 to define EPA as the United States Environmental Protection Agency.

The Commission amends the definition of "good faith claim" in §5.102(30).

The Commission amends §5.102 to add a new paragraph (47) to define "stratigraphic test well." The Commission also adopts new §5.102(51) to define "UIC" as Underground Injection Control.

Amendments to §5.201

The Commission amends §5.201 to add a new subsection (h) regarding requirements for stratigraphic test wells.

Amendments to §5.203

The Commission adopts amendments in §5.203. First, the Commission amends §5.203(a)(1)(B)(iii) to describe federal signatories to permit applications and required reports should a federal agency submit a Class VI UIC permit application consistent with 40 CFR §144.32(a)(3)(ii).

The Commission amends §5.203(a)(2)(C) to replace the word "relevant" with "required" consistent with the federal requirement at 40 CFR §144.31(e)(6).

The Commission amends §5.203(a)(2) to add new subparagraph (E) to require that the application for a Class VI UIC well indicate whether the geologic storage project is located on Indian lands consistent with the federal requirements. The Commission also amends §5.203(a)(2) to add new subparagraph (F) to require that the application include a list of contacts for those States, Tribes, and Territories any portion of which is identified to be within the area of review (AOR) of the geologic storage project based on the map showing the injection well and the AOR consistent with 40 CFR §146.82(a)(2).

The Commission amends §5.203(b)(2)(A) to require that the applicant show within the AOR on the map the number or name and location of stratigraphic boreholes consistent with 40 CFR §146.82(a)(2).

The Commission amends §5.203(d)(1)(C), which requires the applicant to demonstrate that abandoned wells in the AOR have been plugged in a manner that prevents the movement of carbon dioxide or other fluids that may endanger USDWs. The amendment requires a demonstration that the materials used are compatible with the carbon dioxide stream consistent with 40 CFR §146.84(c)(3).

The Commission amends §5.203(d)(2)(B) to clarify that the AOR must be reevaluated at a fixed frequency not to exceed five years throughout the life of the geologic storage facility consistent with the federal requirements at 40 CFR §§146.84(b)(2)(i) and 146.84(e).

The Commission amends §5.203(e)(1)(B)(v) to clarify that at least one long string casing must extend from the surface to the injection zone and must be cemented by circulating cement to the surface in one or more stages consistent with 40 CFR §146.86(b)(3).

The Commission amends §5.203(e)(2)(D) to require an applicant to provide to the Commission in the application the external pressure, internal pressure, and axial loading consistent with the requirements in 40 CFR §146.86(b)(1)(ii).

The Commission amends §5.203(e)(4) to clarify that the applicant must include a description of the stimulation fluids in its description of the proposed well stimulation program if the well is to be stimulated consistent with 40 CFR §146.82(a)(9).

The Commission amends §5.203(f) to amend the title of the subsection to clarify that the plan for logging, sampling, and testing applies to logging, sampling and testing before injection.

The Commission also amends §5.203(f)(3)(B) to clarify that the operator must take whole cores or sidewall cores representative of the injection zone and confining zone and formation fluid samples from the injection zone and must submit to the director a detailed report prepared by a log analyst. The director may require the operator to core other formations in the borehole. The amendment further clarifies that the director may accept data from cores and formation fluid samples from nearby wells or other data if the operator can demonstrate to the director that such data are representative of conditions at the proposed injection well. The amendments to §5.203(f) are consistent with 40 CFR §146.87(b).

The Commission amends §5.203(j)(2)(C), which relates to the requirement for a plan for monitoring, sampling, and testing after initiation of operation. The amendments state that the plan must include a requirement for the performance of corrosion monitoring of the well materials on a quarterly, rather than semi-annual, basis. The amendments change the reporting requirements such that monitoring results must be reported on a semi-annual, rather than annual, basis consistent with 40 CFR §146.90(c).

The Commission amends §5.203(j)(2) to add new subparagraph (F). The new subparagraph requires that the plan include a demonstration of external mechanical integrity at least once per year until the injection well is plugged, and, if required by the director, a casing inspection log at a frequency established in the testing and monitoring plan consistent with 40 CFR §146.90(e). The Commission redesignates §5.203(j)(2)(F) as §5.203(j)(2)(G) and §5.203(j)(2)(G) as §5.203(j)(2)(H).

The Commission amends §5.203(m)(8)(D) to include examples of existing information (e.g., at Class I, Class II, or Class V experimental technology well sites). This amendment is consistent with the federal requirements at 40 CFR §146.93(c)(2)(iv).

Amendments to §5.204

The Commission amends §5.204 to require that the Commission give notice of a draft permit or a public hearing to any State, Tribe, or Territory any portion of which is within the AOR of the Class VI project consistent with 40 CFR §146.82(b). The Commission redesignates (xi) as (xii) and (xii) as (xiii).

The Commission amends §5.204(b)(5) to clarify that, upon making a final permit decision, the director shall issue a response to comments, which must specify which provisions, if any, of the draft permit have been changed in the final permit decision, and the reasons for the change, and briefly describe and respond to all significant comments on the draft permit raised during the public comment period or during any hearing.

Furthermore, the Commission must post the response to comments on the Commission's internet website. These amendments are consistent with 40 CFR §124.17.

Amendments to §5.205

The Commission amends §5.205(c) to state that the director shall consider and approve the applicant's demonstration of financial responsibility for all the phases of the geologic sequestration project, including the post-injection storage facility care and closure phase and the plugging phase, prior to issuance of a geologic storage injection well permit.

The Commission amends §5.205(c)(2)(A)(i) and (C)(i) for consistency with 40 CFR §146.85(a)(2)(ii).

The Commission amends §5.205(c)(2)(C)(i) to clarify that the amount of financial assurance required to be filed under this subchapter must include plugging, and that the cost estimate must be performed for each phase separately and must be based on the costs to the regulatory agency of hiring a third party to perform the required activities. A third party is a party who is not within the corporate structure of the owner or operator.

The Commission amends §5.205(c)(2)(D) to add new (iii) to clarify that the qualifying financial responsibility instruments must comprise protective conditions of coverage. In addition, the amendments specify requirements for cancellation or termination of financial instruments, renewal of financial instruments, cancellation notice, and alternate financial responsibility.

The Commission adopts new §5.205(c)(2)(D)(iii)(III) to state that cancellation, termination, or failure to renew may not occur and the financial instrument will remain in full force and effect if on or before the date of expiration: the director deems the facility abandoned; the permit is terminated or revoked or a new permit is denied; closure is ordered by the director or a U.S. district court or other court of competent jurisdiction; the operator is named as debtor in a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code; or the amount due is paid. These amendments are consistent with 40 CFR §146.85(a)(4).

The Commission amends §5.205(c)(2)(E) to require that, during the active life of the geologic storage project, adjustments for inflation be provided to the director.

The Commission amends §5.205(c)(2)(F) to clarify that the director must approve annual written updates of the cost estimate to increase or decrease the cost estimate to account for any changes to the AOR and corrective action plan, the emergency response and remedial action plan, the injection well plugging plan, and the PISC and closure plan. The amendments address revisions to the cost estimate and requirements for decreasing the value of financial assurance. These amendments are consistent with the federal requirements in 40 CFR §146.85(c)(1).

The Commission amends §5.205(c)(2) to add new subparagraph (G) to clarify requirements when the current cost estimate increases to an amount greater than the face amount of a financial instrument currently in use. Whenever the current cost estimate decreases, the face amount of the financial assurance instrument may be reduced to the amount of the current cost estimate only after written approval from the director. These amendments are consistent with the federal requirements in 40 CFR §146.85(e).

The Commission amends §5.205(c)(2) to add new subparagraph (H) to state that the requirement to maintain adequate financial responsibility is directly enforceable regardless of whether the requirement is a condition of the permit. New subparagraph (H)(i) clarifies the period of time financial responsibility must be maintained. New subparagraph (H)(ii) addresses when an operator may be released from a financial instrument. These amendments are consistent with the requirements at 40 CFR §146.85(b)(2).

The Commission amends §5.205(c) to add new paragraph (5) to clarify that the operator must maintain the required financial responsibility regardless of the status of the director's review of the financial responsibility demonstration consistent with 40 CFR §146.85(a)(5)(ii).

Amendments to §5.206

The Commission amends §5.206(a) to divide the subsection into two paragraphs. New paragraph (2) clarifies that a permit will include a condition that states that the permit may be modified, revoked and reissued, or terminated for cause and that the filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition. These amendments are consistent with the requirements in 40 CFR §144.51(f).

The Commission amends §5.206(b) to add new paragraph (4) to state that the director may issue a permit under this subchapter if the applicant demonstrates and the director finds that the construction, operation, maintenance, conversion, plugging, abandonment, or any other injection activity does not allow the movement of fluid containing any contaminant into USDWs, if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR Part 142 or may otherwise adversely affect the health of persons. This amendment is consistent with the federal requirements in 40 CFR §144.12(a).

The Commission amends §5.206(c)(2) to clarify that the well completion information must be filed on Commission Form W-2, Oil Well Potential Test, Completion or Recompletion Report and Log. This amendment is consistent with the federal requirements in 40 CFR §146.82(c)(5). The Commission Form W-2, and all other Commission forms, can be found by clicking on the "Forms" tab on the Commission's website.

The Commission amends §5.206(d)(1) to clarify the information that the operator must submit and the director must consider before granting approval for the operation of a Class VI injection well. New subparagraph (A) includes the existing language. New subparagraph (B) clarifies that, prior to approval for the operation of a Class VI injection well, the operator shall submit, and the director shall consider, certain information.

These amendments are consistent with the federal requirements in 40 CFR §146.82(c) and distinguish between the requirements of the initial permit application and the requirements to update any permit application/permit elements prior to granting approval to inject.

The Commission amends §5.206(e) to add new paragraph (5).

The Commission also amends §5.206(f) to revise paragraph (2) add a permit condition that clarifies that the operator must establish mechanical integrity prior to commencing injection. The Commission adds new paragraph (3) to add a permit condition that states that, if the director determines that the injection well lacks mechanical integrity, the director shall give written notice of the director's determination to the operator. Unless the director requires immediate cessation, the operator shall cease injection into the well within 48 hours of receipt of the director's determination. The director may allow plugging of the well pursuant or require the permittee to perform such additional construction, operation, monitoring, reporting and corrective action as is necessary to prevent the movement of fluid into or between USDWs caused by the lack of mechanical integrity. The operator may resume injection upon written notification of the director's determination that the operator has demonstrated the well has mechanical integrity.

The Commission adds new paragraph (4) in §5.206(f) to add a permit condition detailing requirements for wells that lack internal mechanical integrity. Existing paragraph (4) is renumbered (5).

These amendments ensure that the rules meet the minimum standards of the federal requirements in 40 CFR §144.51.

The Commission also amends §5.206(g) to clarify that the AOR must be reevaluated at a minimum frequency not to exceed five years as specified in the approved AOR and corrective action plan. In addition, the AOR must be reevaluated whenever warranted by a material change in the monitoring and/or operational data or in the evaluation of the monitoring and operational data by the operator.

The Commission amends §5.206(g)(4) to clarify that any amendments to the AOR and corrective action plan must be approved by the director, must be incorporated into the permit, and are subject to the permit modification requirements in §5.202.

The Commission adds new subsection (g)(5) to require that the operator retain all modeling inputs and data used to support AOR reevaluations for at least 10 years.

The Commission amends §5.206(h)(1) to clarify that the emergency and remedial response plan and the demonstration of financial responsibility must account for the AOR delineated as specified in §5.203(d)(1)(A) - (C) or the most recently evaluated AOR delineated under subsection (g) of §5.206, regardless of whether or not corrective action in the AOR is phased consistent with 40 CFR §146.84(f).

The Commission amends §5.206(h)(3) to clarify that, if any water quality monitoring of an USDW indicates the movement of any contaminant into the USDW, except as authorized by an aquifer exemption, the director shall prescribe such additional requirements for construction, corrective action, operation, monitoring, or reporting (including plugging of the injection well) as are necessary to prevent such movement. This amendment is consistent with the federal requirements in 40 CFR §144.12(b).

The Commission amends §5.206(k)(5) require the operator to submit a plugging record (Form W-3) as required by §3.14 of this title (relating to Plugging) after the director has authorized storage facility closure and plugged all wells in accordance with the approved plugging plan. This amendment is consistent with the federal requirements in 40 CFR §144.52(a)(7)(i).

The Commission amends §5.206(m) to clarify the records the operator must retain. This amendment is consistent with the federal requirements in 40 CFR §146.91(f).

The Commission amends §5.206(o)(1) to clarify that permits issued under Subchapter B of Chapter 5 shall be issued for the operating life of the facility and the post-injection storage facility care period. The director shall review each permit at least once every five years to determine whether it should be modified, revoked and reissued, or terminated.

The Commission amends §5.206(o)(2) to specify permit conditions such as modification, revocation, and termination; signatory requirements; reporting requirements; non-compliance; incorporating other requirements in permits; and compliance with the SWDA. These amendments are consistent with the federal requirements in 40 CFR §144.52.

Amendments to §5.207

The Commission amends §5.207(a)(2)(A) to require the operator to report certain operating information to the director and the appropriate district office orally as soon as practicable, but within 24 hours of discovery, and in writing within five working days of discovery. The amendments specify the contents of the written submission.

The Commission amends §5.207(a)(2)(A) to add new clause (i), which is existing language revised to delete repetitive language. New clause (ii) would require reporting of any evidence that the injected CO_2 stream or associated pressure front may cause an endangerment to a USDW. New clause (iii) requires reporting of any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs. New clause (iv) requires the reporting of any triggering of a shut-off system (i.e., down-hole or at the surface). New clause (v) requires the reporting of any failure to maintain mechanical integrity. These amendments are consistent with the federal requirements in 40 CFR §146.91(c)(2).

The Commission reorganizes §5.207(a)(2)(D) and adds new (E) to clarify requirements for annual reports and updates.

The Commission amends §5.207(e) to specify requirements for retaining certain data. New §5.207(e)(6) and (7) clarify that the director has authority to require the operator to retain any records required in Subchapter B for longer than 10 years after storage facility closure and to require the operator to submit the records to the director at the conclusion of the retention period. These amendments are consistent with 40 CFR §146.91(f).

The Commission adopts the amendments pursuant to Texas Natural Resources Code, §§81.051 and 81.052, which give the Commission jurisdiction over all persons owning or engaged in drilling or operating oil or gas wells in Texas and the authority to adopt all necessary rules for governing and regulating persons and their operations under the jurisdiction of the Commission; Texas Natural Resources Code, Chapter 91, Subchapter R, relating to authorization for multiple or alternative uses of wells; Texas Water Code, Chapter 27, Subchapter C-1, which gives the Commission jurisdiction over the geologic storage of carbon dioxide in, and the injection of carbon dioxide into, a reservoir that is initially or may be productive of oil, gas, or geothermal resources or a saline formation directly above or below that reservoir; Texas Health and Safety Code §382.502, which allows the Commission to adopt by rule standards for the location, construction, maintenance, monitoring, and operation of a carbon dioxide repository and requires the Commission to ensure standards comply with federal requirements issued by the EPA; and Texas Water Code, Chapter 120, which establishes the Anthropogenic Carbon Dioxide Storage Trust Fund, a special interest-bearing fund in the state treasury, to consist of fees collected by the Commission and penalties imposed under Texas Water Code, Chapter 27, Subchapter C-1, and to be used by the Commission for only certain specified activities associated with geologic storage facilities and associated anthropogenic carbon dioxide injection wells.

Statutory authority: Texas Natural Resources Code, §§81.051, 81.052; Texas Natural Resources Code, Chapter 91, Subchapter R; Texas Health and Safety Code §382.502; and Texas Water Code, Chapters 27 and 120.

Cross reference to statute: Texas Natural Resources Code, Chapters 81 and 91, Texas Health and Safety Code, Chapter 382, and Texas Water Code, Chapters 27 and 120.

SUBCHAPTER A. GENERAL PROVISIONS

§5.102 Definitions.

The following terms, when used in Subchapter B of this chapter, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Affected person--A person who, as a result of activity sought to be permitted has suffered or may suffer actual injury or economic damage other than as a member of the general public.

(2) Anthropogenic carbon dioxide (CO_2)--

(A) CO_2 that <u>has been captured from or</u> would otherwise have been released into the atmosphere that has been:

(i) separated from any other fluid stream; or

(ii) captured from an emissions source, including:

(I) an advanced clean energy project as defined by Health and Safety Code, §382.003, or another type of electric generation facility; or

(II) an industrial source of emissions; and

(iii) any incidental associated substance derived from the source material for, or from the process of capturing, CO_2 described by clause (i) of this subparagraph; and

(iv) any substance added to CO_2 described by clause (i) of this subparagraph to enable or improve the process of injecting the CO_2; and

(B) does not include naturally occurring CO_2 that is produced, acquired, recaptured, recycled, and reinjected as part of enhanced recovery operations.

(3) Anthropogenic CO_2 injection well--An injection well used to inject or transmit gaseous, liquid, or supercritical anthropogenic CO_2 into a reservoir.

(4) Aquifer--A geologic formation, group of formations, or part of a formation that is capable of yielding a significant amount of water to a well or spring.

(5) Area of review (AOR)--The subsurface three-dimensional extent of the CO_2 stream plume and the associated pressure front, as well as the overlying formations, any underground sources of drinking water overlying an injection zone along with any intervening formations, and the surface area above that delineated region.

(6) Carbon dioxide (CO_2) plume--The underground extent, in three dimensions, of an injected CO_2 stream.

(7) Carbon dioxide (CO_2) stream--CO_2 that has been captured from an emission source or the atmosphere, incidental associated substances derived from the source materials and the capture process, and any substances added to the stream to enable or improve the injection process. The term does not include any CO_2 stream that meets the definition of a hazardous waste under 40 CFR Part 261.

(8) Casing--A pipe or tubing of appropriate material, of varying diameter and weight, lowered into a borehole during or after drilling in order to support the sides of the hole and thus prevent the walls from caving, to prevent loss of drilling mud into porous ground, or to prevent water, gas, or other fluid from entering or leaving the hole.

(9) Cementing--The operation whereby a cement slurry is pumped into a drilled hole and/or forced behind the casing.

(10) Class VI well--Any well used to inject anthropogenic CO_2 specifically for the purpose of the long-term containment of a gaseous, liquid, or supercritical CO_2 in subsurface geologic formations.

(11) Code of Federal Regulations (CFR)--The codification of the general and permanent rules published in the *Federal Register* by the executive departments and agencies of the federal government.

(12) Commission--A quorum of the members of the Railroad Commission of Texas convening as a body in open meeting.

(13) Confining zone--A geologic formation, group of formations, or part of a formation stratigraphically overlying the injection zone or zones that acts as barrier to fluid movement. For Class VI wells operating under an injection depth waiver, confining zone means a geologic formation, group of formations, or part of a formation stratigraphically overlying and underlying the injection zone or zones that acts as a barrier to fluid movement.

(14) Corrective action--Methods to assure that wells within the area of review do not serve as conduits for the movement of fluids into or between underground sources of drinking water, including the use of corrosion resistant materials, where appropriate.

(15) Delegate--The person authorized by the director to take action on behalf of the Railroad Commission of Texas under this chapter.

(16) Director--The director of the Oil and Gas Division of the Railroad Commission of Texas or the director's delegate.

(17) Division--The Oil and Gas Division of the Railroad Commission of Texas.

(18) Draft permit--A document prepared indicating the director's tentative decision to issue or deny, modify, revoke and reissue, terminate, or reissue a permit. A notice of intent to terminate a permit, and a notice of intent to deny a permit are types of "draft permits." A denial of a request for modification, revocation and reissuance, or termination is not a draft permit.

(19) Enhanced recovery operation--Using any process to displace hydrocarbons from a reservoir other than by primary recovery, including using any physical, chemical, thermal, or biological process and any co-production project. This term does not include pressure maintenance or disposal projects.

(20) EPA--The United States Environmental Protection Agency.

(21) [~~(20)~~] Exempted aquifer--An aquifer or its portion that meets the criteria in the definition of underground source of drinking water but which has been exempted according to the procedures in 40 CFR §144.7.

(22) [~~(21)~~] Facility closure--The point at which the operator of a geologic storage facility is released from post-injection storage facility care responsibilities.

(23) [~~(22)~~] Flow rate--The volume per time unit given to the flow of gases or other fluid substance which emerges from an orifice, pump, turbine or passes along a conduit or channel.

(24) [~~(23)~~] Fluid--Any material or substance which flows or moves whether in a semisolid, liquid, sludge, gas, or any other form or state.

(25) [~~(24)~~] Formation--A body of consolidated or unconsolidated rock characterized by a degree of lithologic homogeneity which is prevailingly, but not necessarily, tabular and is mappable on the earth's surface or traceable in the subsurface.

(26) [~~(25)~~] Formation fluid--Fluid present in a formation under natural conditions.

(27) [~~(26)~~] Fracture pressure--The pressure that, if applied to a subsurface formation, would cause that formation to physically fracture.

(28) [~~(27)~~] Geologic storage--The long-term containment of gaseous, liquid, or supercritical anthropogenic CO_2 in subsurface geologic formations.

(29) [~~(28)~~] Geologic storage facility or storage facility--The underground geologic formation, underground equipment, injection wells, and surface buildings and equipment used or to be used for the

geologic storage of anthropogenic CO_2 and all surface and subsurface rights and appurtenances necessary to the operation of a facility for the geologic storage of anthropogenic CO_2. The term includes the subsurface three-dimensional extent of the CO_2 plume, associated area of elevated pressure, and displaced fluids, as well as the surface area above that delineated region, and any reasonable and necessary areal buffer and subsurface monitoring zones. The term does not include a pipeline used to transport CO_2 from the facility at which the CO_2 is captured to the geologic storage facility. The storage of CO_2 incidental to or as part of enhanced recovery operations does not in itself automatically render a facility a geologic storage facility.

(30) [~~(29)~~] Good faith claim--A factually supported claim based on a recognized legal theory to a **continuing possessory right** in pore space **such that the pore space can be** used for geologic storage of carbon dioxide[~~, such as evidence of a currently valid lease~~].

(31) [~~(30)~~] Injection zone--A geologic formation, group of formations, or part of a formation that is of sufficient areal extent, thickness, porosity, and permeability to receive CO_2 through a well or wells associated with a geologic storage facility.

(32) [~~(31)~~] Injection well--A well into which fluids are injected.

(33) [~~(32)~~] Interested person--Any person who expresses an interest in an application, permit, or Class VI UIC well.

(34) [~~(33)~~] Limited English-speaking household--A household in which all members 14 years and older have at least some difficulty with English.

(35) [~~(34)~~] Lithology--The description of rocks on the basis of their physical and chemical characteristics.

(36) [~~(35)~~] Mechanical integrity--

(A) An anthropogenic CO_2 injection well has mechanical integrity if:

(i) there is no significant leak in the casing, tubing, or packer; and

(ii) there is no significant fluid movement into a stratum containing an underground source of drinking water through channels adjacent to the injection well bore as a result of operation of the injection well.

(B) The Commission will consider any deviations during testing that cannot be explained by the margin of error for the test used to determine mechanical integrity, or other factors, such as temperature fluctuations, to be an indication of the possibility of a significant leak and/or the possibility of significant fluid movement into a stratum containing an underground source of drinking water through channels adjacent to the injection wellbore.

(37) [~~(36)~~] Monitoring well--A well either completed or re-completed to observe subsurface phenomena, including the presence of anthropogenic CO_2, pressure fluctuations, fluid levels and flow, temperature, and/or in situ water chemistry.

(38) [~~(37)~~] Offshore--The area in the Gulf of Mexico seaward of the coast that is within three marine leagues of the coast.

(39) [~~(38)~~] Operator--A person, acting for itself or as an agent for others, designated to the Railroad Commission of Texas as the person with responsibility for complying with the rules and regulations regarding the permitting, physical operation, closure, and post-closure care of a geologic storage facility, or such person's authorized representative.

(40) Owner--The owner of any facility or activity subject to regulation under the UIC program.

(41) Owner or operator--The owner or operator of any injection well, or any other facility or activity that is subject to regulation under the UIC program. When a geologic storage facility is owned by one person but is operated by another person, it is the operator's duty to comply with the requirements of this subchapter and any permit issued under this subchapter, except that either the owner or the operator may demonstrate financial responsibility.

(42) [~~(39)~~] Packer--A device lowered into a well to produce a fluid-tight seal.

(43) [~~(40)~~] Permit--An authorization, license, or equivalent control document issued by the Commission to implement the requirements of this chapter.

(44) [~~(41)~~] Person--A natural person, corporation, organization, government, governmental subdivision or agency, business trust, estate, trust, partnership, association, or any other legal entity.

(45) [~~(42)~~] Plugging--The act or process of stopping the flow of water, oil or gas into or out of a formation through a borehole or well penetrating that formation.

(46) [~~(43)~~] Post-injection facility care--Monitoring and other actions (including corrective action) needed following cessation of injection to assure that underground sources of drinking water are not endangered and that the anthropogenic CO_2 remains confined to the permitted injection interval.

(47) [~~(44)~~] Pressure front--The zone of elevated pressure that is created by the injection of the CO_2 stream into the subsurface where there is a pressure differential sufficient to cause movement of the CO_2 stream or formation fluids from the injection zone into an underground source of drinking water.

(48) [~~(45)~~] Reservoir--A natural or artificially created subsurface stratum, formation, aquifer, cavity, void, or coal seam.

(49) Stratigraphic test well--An exploratory well drilled for the purpose of gathering information in connection with a proposed carbon dioxide geologic storage project, including formation testing to obtain information on the chemical and physical characteristics of the injection zones and confining zones. Such testing may include injectivity testing.

(50) [~~(46)~~] Stratum (or strata)--A single sedimentary bed or layer, regardless of thickness, that consists of generally the same kind of rock material.

(51) [~~(47)~~] Surface casing--The first string of well casing to be installed in the well.

(52) [~~(48)~~] Transmissive fault or fracture--A fault or fracture that has sufficient permeability and vertical extent to allow fluids to move beyond the confining zone.

(53) UIC--Underground injection control.

(54) [~~(49)~~] Underground source of drinking water (USDW)--An aquifer or its portion which is not an exempt aquifer as defined in 40 CFR §146.4 and which:

(A) supplies any public water system; or

(B) contains a sufficient quantity of ground water to supply a public water system; and

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

(ii) contains fewer than 10,000 mg/l total dissolved solids.

(55) [~~(50)~~] Well injection--The subsurface emplacement of fluids through a well.

(56) [~~(51)~~] Well stimulation--Any of several processes used to clean the well bore, enlarge channels, and increase pore space in the interval to be injected thus making it possible for fluid to move more readily into the formation including, but not limited to, surging, jetting, blasting, acidizing, and hydraulic fracturing.

(57) [~~(52)~~] Workover--An operation in which a down-hole component of a well is repaired or the engineering design of the well is changed. Workovers include operations such as sidetracking, the addition of perforations within the permitted injection interval, and the addition of liners or patches. For the purposes of this chapter, workovers do not include well stimulation operations.

SUBCHAPTER B. GEOLOGIC STORAGE AND ASSOCIATED INJECTION OF ANTHROPOGENIC CARBON DIOXIDE (CO_2)

§5.201. Applicability and Compliance.

(a) Scope of jurisdiction. This subchapter applies to the geologic storage and associated injection of anthropogenic CO_2 in this state, both onshore and offshore.

(b) Injection of CO_2 for enhanced recovery.

(1) This subchapter does not apply to the injection of fluid through the use of an injection well regulated under §3.46 of this title (relating to Fluid Injection into Productive Reservoirs) for the primary purpose of enhanced recovery operations from which there is reasonable expectation of more than insignificant future production volumes of oil, gas, or geothermal energy and operating pressures are no higher than reasonably necessary to produce such volumes or rates. However, the operator of an enhanced recovery project may propose to also permit the enhanced recovery project as a CO_2 geologic storage facility simultaneously.

(2) If the director determines that an injection well that is permitted for the injection of CO_2 for the purpose of enhanced recovery regulated under §3.46 of this title should be regulated under this subchapter because the injection well is no longer being used for the primary purpose of enhanced recovery operations or there is an increased risk to USDWs, the director must notify the operator of such determination and allow the

operator at least 30 days to respond to the determination and to file an application under this subchapter or cease operation of the well. In determining if there is an increased risk to USDWs, the director shall consider the following factors:

(A) increase in reservoir pressure within the injection zone;

(B) increase in CO_2 injection rates;

(C) decrease in reservoir production rates;

(D) distance between the injection zone and USDWs;

(E) suitability of the enhanced oil or gas recovery AOR delineation;

(F) quality of abandoned well plugs within the AOR;

(G) the storage operator's plan for recovery of CO_2 at the cessation of injection;

(H) the source and properties of injected CO_2; and

(I) any additional site-specific factors as determined by the director.

(3) This subchapter does not preclude an enhanced oil recovery project operator from opting into a regulatory program that provides carbon credit for anthropogenic CO_2 sequestered through the enhanced recovery project.

(c) Injection of acid gas. This subchapter does not apply to the disposal of acid gas generated from oil and gas activities from leases, units, fields, or a gas processing facility. Injection of acid gas that contains CO_2 and that was generated as part of oil and gas processing may continue to be permitted as a Class II injection well. The potential need to transition a well from Class II to Class VI shall be based on the increased risk to USDWs related to significant storage of CO_2 in the reservoir, where the regulatory tools of the Class II program cannot successfully manage the risk. In determining if there is an increased risk to USDWs, the director shall consider the following factors:

(1) the reservoir pressure within the injection zone;

(2) the quantity of acid gas being disposed of;

(3) the distance between the injection zone and USDWs;

(4) the suitability of the disposed waste AOR delineation;

(5) the quality of abandoned well plugs within the AOR;

(6) the source and properties of injected acid gas; and

(7) any additional site-specific factors as determined by the director.

(d) This subchapter applies to a well that is authorized as or converted to an anthropogenic CO_2 injection well for geologic storage (a Class VI injection well). This subchapter applies regardless of whether the well was initially completed for the purpose of injection and geologic storage of anthropogenic CO_2 or was initially completed for another purpose and is converted to the purpose of injection and geologic storage of anthropogenic CO_2, except that the Commission may not issue a permit under this subchapter for the conversion of a previously plugged and abandoned Class I injection well, including any associated waste plume, to a Class VI injection well.

(e) Expansion of aquifer exemption. The areal extent of an aquifer exemption for a Class II enhanced recovery well may be expanded for the exclusive purpose of Class VI injection for geologic storage if the aquifer does not currently serve as a source of drinking water; and the total dissolved solids content is more than 3,000 milligrams per liter (mg/l) and less than 10,000 mg/l; and it is not reasonably expected to supply a public water system in accordance with 40 CFR §146.4. An operator seeking such an expansion shall submit, concurrent with the permit application, a supplemental report that complies with 40 CFR §144.7(d). The Commission adopts 40 CFR §144.7 and §146.4 by reference, effective September 20, 2022.

(f) Injection depth waiver. An operator may seek a waiver from the Class VI injection depth requirements for geologic storage to allow injection into non-USDW formations while ensuring that USDWs above and below the injection zone are protected from endangerment. An operator seeking a waiver of the requirement to inject below the lowermost USDW shall submit, concurrent with the permit application or a permit amendment application, a supplemental report that complies with 40 CFR §146.95. The Commission adopts 40 CFR §146.95 by reference, effective September 20, 2022.

(g) This subchapter does not apply to the injection of any CO_2 stream that meets the definition of a hazardous waste under 40 CFR Part 261.

<u>(h) An operator shall apply for a permit to drill (Form W-1) prior to drilling a stratigraphic test well, notify the UIC Section of the application, and submit a completion report (Form W-2/G-1) once the well is completed. If the operator plans to convert the stratigraphic test well to a Class VI injection well, the well construction shall meet all of the requirements of this subchapter for a Class VI injection well. Any stratigraphic test well drilled for exploratory purposes only shall be governed by the provisions of Commission rules in Chapter 3 of this title (relating to Oil and Gas Division) applicable to the drilling, safety, casing, abandoning, and plugging of wells. **As an alternative to drilling a stratigraphic test well, an operator may obtain data for site characterization from offset wells.**</u>

<u>(i)</u> [~~(h)~~] If a provision of this subchapter conflicts with any provision or term of a Commission order or permit, the provision of such order or permit controls <u>**provided that the provision satisfies the minimum requirements for EPA's Class VI UIC program**</u>.

<u>(j)</u> [~~(i)~~] The operator of a geologic storage facility must comply with the requirements of this subchapter as well as with all other applicable Commission rules and orders, including the requirements of Chapter 8 of this title (relating to Pipeline Safety Regulations) for pipelines and associated facilities.

§5.203. Application Requirements.

(a) General.

(1) Form and filing; signatories; certification.

(A) Form and filing. Each applicant for a permit to construct and operate a geologic storage facility must file an application with the division in Austin on a form prescribed by the Commission. The applicant must file the application and all attachments with the division and with EPA Region 6 in an electronic format approved by EPA. On the same date, the applicant must file one copy with each appropriate district office and one copy with the Executive Director of the Texas Commission on Environmental Quality.

(B) Signatories to permit applications. An applicant must ensure that the application is executed by a party having knowledge of the facts entered on the form and included in the required attachments. All permit applications shall be signed as specified in this subparagraph:

(i) For a corporation, the permit application shall be signed by a responsible corporate officer. For the purpose of this section, a responsible corporate officer means a president, secretary, treasurer, or vice president of the corporation in charge of a principal business function, or any other person who performs similar policy- or decision-making functions for the corporation, or the manager of one or more manufacturing, production, or operating facilities employing more than 250 persons or having gross annual sales or expenditures exceeding $25 million (in second-quarter 1980 dollars), if authority to sign documents has been assigned or delegated to the manager in accordance with corporate procedures.

(ii) For a partnership or sole proprietorship, the permit application shall be signed by a general partner or the proprietor, respectively.

(iii) For a municipality, State, Federal, or other public agency, the permit application shall be signed by either a principal executive officer or ranking elected official. <u>For purposes of this section, a principal executive officer of a federal agency includes the chief executive officer of the agency or a senior executive officer having responsibility for the overall operations of a principal geographic unit of the agency.</u>

(C) Certification. Any person signing a permit application or permit amendment application shall make the following certification: "I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations."

(2) General information.

(A) On the application, the applicant must include the name, mailing address, and location of the facility for which the application is being submitted and the operator's name, address, telephone number, Commission Organization Report number, and ownership of the facility.

(B) When a geologic storage facility is owned by one person but is operated by another person, it is the operator's duty to file an application for a permit.

(C) The application must include a listing of all required [~~relevant~~] permits or construction approvals for the facility received or applied for under federal or state environmental programs;

(D) A person making an application to the director for a permit under this subchapter must submit a copy of the application to the Texas Commission on Environmental Quality (TCEQ) and must submit to the director a letter of determination from TCEQ concluding that drilling and operating an anthropogenic CO_2 injection well for geologic storage or constructing or operating a geologic storage facility will not impact or interfere with any previous or existing Class I injection well, including any associated waste plume, or any other injection well authorized or permitted by TCEQ. The letter must be submitted to the director before any permit under this subchapter may be issued.

(E) The application must indicate whether the geologic storage project is located on Indian lands.

(F) The application must include a list of contacts for those States, Tribes, and Territories any portion of which is identified to be within the AOR of the geologic storage project based on the map showing the injection well and the AOR.

(3) Application completeness. The Commission shall not issue a permit before receiving a complete application. A permit application is complete when the director determines that the application contains information addressing each application requirement of the regulatory program and all information necessary to initiate the final review by the director.

(4) Reports. An applicant must ensure that all descriptive reports are prepared by a qualified and knowledgeable person and include an interpretation of the results of all logs, surveys, sampling, and tests required in this subchapter. The applicant must include in the application a quality assurance and surveillance plan for all testing and monitoring, which includes, at a minimum, validation of the analytical laboratory data, calibration of field instruments, and an explanation of the sampling and data acquisition techniques.

(5) If otherwise required under Occupations Code, Chapter 1001, relating to Texas Engineering Practice Act, or Chapter 1002, relating to Texas Geoscientists Practice Act, respectively, a licensed professional engineer or geoscientist must conduct the geologic and hydrologic evaluations required under this subchapter and must affix the appropriate seal on the resulting reports of such evaluations.

(b) Surface map and information. Only information of public record is required to be included on this map.

(1) The applicant must file with the director a surface map delineating the proposed location **and geographic coordinates** of any injection wells**, any proposed monitoring wells,** and the boundary of the geologic storage facility for which a permit is sought and the applicable AOR. **The applicant must indicate the coordinate system used.**

(2) The applicant must show within the AOR on the map the number or name and the location of:

(A) all known artificial penetrations through the confining zone, including stratigraphic boreholes, injection wells, producing wells, inactive wells, plugged wells, or dry holes;

(B) the locations of cathodic protection holes, subsurface cleanup sites, bodies of surface water, springs, surface and subsurface mines, quarries, and water wells; and

(C) other pertinent surface features, including pipelines, roads, and structures intended for human occupancy.

(3) The applicant must identify on the map any known or suspected faults expressed at the surface.

(c) Geologic, geochemical, and hydrologic information.

(1) The applicant must submit a descriptive report prepared by a knowledgeable person that includes an interpretation of the results of appropriate logs, surveys, sampling, and testing sufficient to determine the depth, thickness, porosity, permeability, and lithology of, and the geochemistry of any formation fluids in, all relevant geologic formations.

(2) The applicant must submit information on the geologic structure and reservoir properties of the proposed storage reservoir and overlying formations, including the following information:

(A) geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the area from the ground surface to the base of the injection zone within the AOR that indicate the general vertical and lateral limits of all USDWs within the AOR, their positions relative to the storage reservoir and the direction of water movement, where known;

(B) the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of, and the geochemistry of any formation fluids in, the storage reservoir and confining zone and any other relevant geologic formations, including geology/facies changes based on field data, which may include geologic cores, outcrop data, seismic surveys, well logs, and lithologic descriptions, and the analyses of logging, sampling, and testing results used to make such determinations;

(C) the location, orientation, and properties of known or suspected transmissive faults or fractures that may transect the confining zone within the AOR and a determination that such faults or fractures would not compromise containment;

(D) the seismic history, including the presence and depth of seismic sources, and a determination that the seismicity would not compromise containment;

(E) geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone;

(F) a description of the formation testing program used and the analytical results used to determine the chemical and physical characteristics of the injection zone and the confining zone; and

(G) baseline geochemical data for subsurface formations that will be used for monitoring purposes, including all formations containing USDWs within the AOR.

(d) AOR and corrective action. This subsection describes the standards for the information regarding the delineation of the AOR, the identification of penetrations, and corrective action that an applicant must include in an application.

(1) Initial delineation of the AOR and initial corrective action. The applicant must delineate the AOR, identify all wells that require corrective action, and perform corrective action on those wells. Corrective action may be phased.

(A) Delineation of AOR.

(i) Using computational modeling that considers the volumes and/or mass and the physical and chemical properties of the injected CO_2 stream, the physical properties of the formation into which the CO_2 stream is to be injected, and available data including data available from logging, testing, or operation of wells, the applicant must predict the lateral and vertical extent of migration for the CO_2 plume and formation fluids and the pressure differentials required to cause movement of injected fluids or formation fluids into a USDW in the subsurface for the following time periods:

(I) five years after initiation of injection;

(II) from initiation of injection to the end of the injection period proposed by the applicant; and

(III) from initiation of injection until the movement of the CO_2 plume and associated pressure front stabilizes.

(ii) The applicant must use a computational model that:

(I) is based on geologic and reservoir engineering information collected to characterize the injection zone and the confining zone;

(II) is based on anticipated operating data, including injection pressures, rates, temperatures, and total volumes and/or mass over the proposed duration of injection;

(III) takes into account relevant geologic heterogeneities and data quality, and their possible impact on model predictions;

(IV) considers the physical and chemical properties of injected and formation fluids; and

(V) considers potential migration through known faults, fractures, and artificial penetrations and beyond lateral spill points.

(iii) The applicant must provide the name and a description of the model, software, the assumptions used to determine the AOR, and the equations solved.

(B) Identification and table of penetrations. The applicant must identify, compile, and submit a table listing all penetrations, including active, inactive, plugged, and unplugged wells and underground mines in the AOR that may penetrate the confining zone, that are known or reasonably discoverable through specialized knowledge or experience. The applicant must provide a description of each penetration's type, construction, date drilled or excavated, location, depth, and record of plugging and/or completion or closure. Examples of specialized knowledge or experience may include reviews of federal, state, and local government records, interviews with past and present owners, operators, and occupants, reviews of historical information (including aerial photographs, chain of title documents, and land use records), and visual inspections of the facility and adjoining properties.

(C) Corrective action. The applicant must demonstrate whether each of the wells on the table of penetrations has or has not been plugged and whether each of the underground mines (if any) on the table of penetrations has or has not been closed in a manner that prevents the movement of injected fluids or displaced formation fluids that may endanger USDWs or allow the injected fluids or formation fluids to escape the permitted injection zone. <u>The demonstration shall include evidence that the materials used are compatible with the carbon dioxide stream.</u> The applicant must perform corrective action on all wells and underground mines in the AOR that are determined to need corrective action. The operator must perform corrective action using materials suitable for use with the CO_2 stream. Corrective action may be phased.

(2) AOR and corrective action plan. As part of an application, the applicant must submit an AOR and corrective action plan that includes the following information:

(A) the method for delineating the AOR, including the model to be used, assumptions that will be made, and the site characterization data on which the model will be based;

(B) for the AOR, a description of:

(i) the minimum <u>fixed</u> frequency<u>, not to exceed five years,</u> [~~subject to the annual certification pursuant to §5.206(f) of this title (relating to Permit Standards)~~] at which the applicant proposes to re-evaluate the AOR during the life of the geologic storage facility;

(ii) how monitoring and operational data will be used to re-evaluate the AOR; and

(iii) the monitoring and operational conditions that would warrant a re-evaluation of the AOR prior to the next scheduled re-evaluation; and

(C) a corrective action plan that describes:

(i) how the corrective action will be conducted;

(ii) how corrective action will be adjusted if there are changes in the AOR;

(iii) if a phased corrective action is planned, how the phasing will be determined; and

(iv) how site access will be secured for future corrective action.

(e) Injection well construction.

(1) Criteria for construction of anthropogenic CO_2 injection wells. This paragraph establishes the criteria for the information about the construction and casing and cementing of, and special equipment for, anthropogenic CO_2 injection wells that an applicant must include in an application.

(A) General. The operator of a geologic storage facility must ensure that all anthropogenic CO_2 injection wells are constructed and completed in a manner that will:

(i) prevent the movement of injected CO_2 or displaced formation fluids into any unauthorized zones or into any areas where they could endanger USDWs;

(ii) allow the use of appropriate testing devices and workover tools; and

(iii) allow continuous monitoring of the annulus space between the injection tubing and long string casing.

(B) Casing and cementing of anthropogenic CO_2 injection wells.

(i) The operator must ensure that injection wells are cased and the casing cemented in compliance with §3.13 of this title (relating to Casing, Cementing, Drilling, Well Control, and Completion Requirements), in addition to the requirements of this section.

(ii) Casing, cement, cement additives, and/or other materials used in the construction of each injection well must have sufficient structural strength and must be of sufficient quality and quantity to maintain integrity over the design life of the injection well. All well materials must be suitable for use with fluids with which the well materials may be expected to come into contact and must meet or exceed test standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards as approved by the director.

(iii) Surface casing must extend through the base of the lowermost USDW above the injection zone and must be cemented to the surface.

(iv) Circulation of cement may be accomplished by staging. The director may approve an alternative method of cementing in cases where the cement cannot be circulated to the surface, provided the applicant can demonstrate by using logs that the cement does not allow fluid movement between the casing and the well bore.

(v) At least one long string casing, using a sufficient number of centralizers, must extend from the surface to the injection zone and must be cemented by circulating cement to the surface in one or more stages. The long string casing must isolate the injection zone and other intervals as necessary for the protection of USDWs and to ensure confinement of the injected and formation fluids to the permitted injection zone using cement and/or other isolation techniques. If the long string casing does not extend through the injection zone, another well string or liner must be cemented through the injection zone (for example, a chrome liner).

(vi) The applicant must verify the integrity and location of the cement using technology capable of radial evaluation of cement quality and identification of the location of channels to ensure that USDWs will not be endangered.

(vii) The director may exempt existing Class II wells that have been associated with injection of CO_2 for the purpose of enhanced recovery, Class V experimental technology wells, and stratigraphic test wells from provisions of these casing and cementing requirements if the applicant demonstrates that the well construction meets the general performance criteria in subparagraph (A) of this paragraph. A converted well must meet all other requirements under this section. The demonstration must include the following:

(I) as-built schematics and construction procedures to demonstrate that repermitting is appropriate;

(II) recent or newly conducted well-log information and mechanical integrity test results;

(III) a demonstration that any needed remedial actions have been performed;

(IV) a demonstration that the well was engineered and constructed to meet the requirements of subparagraph (A) of this paragraph and ensure protection of USDWs;

(V) a demonstration that cement placement and materials are appropriate for CO_2 injection for geologic storage;

(VI) a demonstration that the well has, and is able to maintain, internal and external mechanical integrity over the life of the project; and

(VII) the results of any additional testing of the well to support a demonstration of suitability for geologic storage.

(C) Special equipment.

(i) Tubing and packer. All injection wells must inject fluids through tubing set on a packer. Packers must be set no higher than 100 feet above the top of the permitted injection interval or at a location approved by the director.

(ii) Pressure observation valve. The wellhead of each injection well must be equipped with a pressure observation valve on the tubing and each annulus of the well.

(2) Construction information. The applicant must provide the following information for each well to allow the director to determine whether the proposed well construction and completion design will meet the general performance criteria in paragraph (1) of this subsection:

(A) depth to the injection zone;

(B) hole size;

(C) size and grade of all casing and tubing strings (e.g., wall thickness, external diameter, nominal weight, length, joint specification and construction material, tubing tensile, burst, and collapse strengths);

(D) proposed injection rate (intermittent or continuous), maximum proposed surface injection pressure, external pressure, internal pressure, axial loading, and maximum proposed volume and [~~and/or~~] mass of the CO_2 stream to be injected;

(E) type of packer and packer setting depth;

(F) a description of the capability of the materials to withstand corrosion when exposed to a combination of the CO_2 stream and formation fluids;

(G) down-hole temperatures and pressures;

(H) lithology of injection and confining zones;

(I) type or grade of cement and additives;

(J) chemical composition and temperature of the CO_2 stream; and

(K) schematic drawings of the surface and subsurface construction details.

(3) Well construction plan. The applicant must submit an injection well construction plan that meets the criteria in paragraph (1) of this subsection.

(4) Well stimulation plan. The applicant must submit[~~, as applicable,~~] a description of the proposed well stimulation program, including a description of the stimulation fluids, and a determination that well stimulation will not compromise containment.

(f) Plan for logging, sampling, and testing of injection wells [~~after permitting but~~] before injection. The applicant must submit a plan for logging, sampling, and testing of each injection well [~~after permitting but~~] prior to injection well operation. The plan need not include identical logging, sampling, and testing procedures for all wells provided there is a reasonable basis for different procedures. Such plan is not necessary for existing wells being converted to anthropogenic CO_2 injection wells in accordance with this subchapter, to the extent such activities already have taken place. The plan must describe the logs, surveys, and tests to be conducted to verify the depth, thickness, porosity, permeability, and lithology of, and the salinity of any formation fluids in, the formations that are to be used for monitoring, storage, and confinement to assure conformance with the injection well construction requirements set forth in subsection (e) of this section, and to establish accurate baseline data against which future measurements may be compared. The plan must meet the following criteria and must include the following information.

(1) Logs and surveys of newly drilled and completed injection wells.

(A) During the drilling of any hole that is constructed by drilling a pilot hole that is enlarged by reaming or another method, the operator must perform deviation checks at sufficiently frequent intervals to determine the location of the borehole and to assure that vertical avenues for fluid movement in the form of diverging holes are not created during drilling.

(B) Before surface casing is installed, the operator must run appropriate logs, such as resistivity, spontaneous potential, and caliper logs.

(C) After each casing string is set and cemented, the operator must run logs, such as a cement bond log, variable density log, and a temperature log, to ensure proper cementing.

(D) Before long string casing is installed, the operator must run logs appropriate to the geology, such as resistivity, spontaneous potential, porosity, caliper, gamma ray, and fracture finder logs, to gather data necessary to verify the characterization of the geology and hydrology.

(2) Testing and determination of hydrogeologic characteristics of injection and confining zone.

(A) Prior to operation, the operator must conduct tests to verify hydrogeologic characteristics of the injection zone.

(B) The operator must perform an initial pressure fall-off or other test and submit to the director a written report of the results of the test, including details of the methods used to perform the test and to interpret the results, all necessary graphs, and the testing log, to verify permeability, injectivity, and initial pressure using water or CO_2.

(C) The operator must determine or calculate the fracture pressures for the injection and confining zone. The Commission will include in any permit it might issue a limit of 90% of the fracture pressure to ensure that the injection pressure does not exceed the fracture pressure of the injection zone.

(3) Sampling.

(A) The operator must record and submit the formation fluid temperature, pH, and conductivity, the reservoir pressure, and the static fluid level of the injection zone.

(B) The operator must take [~~submit analyses of~~] whole cores or sidewall cores representative of the injection zone and confining zone and formation fluid samples from the injection zone. **The director may require the operator to core other formations in the borehole.** The director may accept data from cores and formation fluid samples from nearby wells or other data if the operator can demonstrate to the director that such data are representative of conditions at the proposed injection well. The operator must submit to the director a detailed report prepared by a log analyst that includes well log analyses (including well logs), core analyses, and formation fluid sample information.

(g) Compatibility determination. Based on the results of the formation testing program required by subsection (f) of this section, the applicant must submit a determination of the compatibility of the CO_2 stream with:

(1) the materials to be used to construct the well;

(2) fluids in the injection zone; and

(3) minerals in both the injection and the confining zone.

(h) Mechanical integrity testing.

(1) Criteria. This paragraph establishes the criteria for the mechanical integrity testing plan for anthropogenic CO_2 injection wells that an applicant must include in an application.

(A) Other than during periods of well workover in which the sealed tubing-casing annulus is of necessity disassembled for maintenance or corrective procedures, the operator must maintain mechanical integrity of the injection well at all times.

(B) Before beginning injection operations and at least once every five years thereafter, the operator must demonstrate internal mechanical integrity for each injection well by pressure testing the tubing-casing annulus.

(C) Following an initial annulus pressure test, the operator must continuously monitor injection pressure, rate, temperature, injected volumes and mass, and pressure on the annulus between tubing and long string casing to confirm that the injected fluids are confined to the injection zone. If mass is determined using volume, the operator must provide calculations.

(D) At least once per year until the injection well is plugged, the operator must confirm the absence of significant fluid movement into a USDW through channels adjacent to the injection wellbore (external integrity) using a method approved by the director (e.g., diagnostic surveys such as oxygen-activation logging or temperature or noise logs).

(E) The operator must test injection wells after any workover that disturbs the seal between the tubing, packer, and casing in a manner that verifies internal mechanical integrity of the tubing and long string casing.

(F) An operator must either repair and successfully retest or plug a well that fails a mechanical integrity test.

(2) Mechanical integrity testing plan. The applicant must prepare and submit a mechanical integrity testing plan as part of a permit application. The performance tests must be designed to demonstrate the internal and external mechanical integrity of each injection well. These tests may include:

(A) a pressure test with liquid or inert gas;

(B) a tracer survey such as oxygen-activation logging;

(C) a temperature or noise log;

(D) a casing inspection log; and/or

(E) any alternative method approved by the director, and if necessary by the Administrator of EPA under 40 CFR §146.89(e), that provides equivalent or better information approved by the director.

(i) Operating information.

(1) Operating plan. The applicant must submit a plan for operating the injection wells and the geologic storage facility that complies with the criteria set forth in §5.206(d) of this title, and that outlines the

steps necessary to conduct injection operations. The applicant must include the following proposed operating data in the plan:

(A) the average and maximum daily injection rates, temperature, and volumes and/or mass of the CO_2 stream;

(B) the average and maximum surface injection pressure;

(C) the sources of the CO_2 stream and the volume and/or mass of CO_2 from each source; and

(D) an analysis of the chemical and physical characteristics of the CO_2 stream prior to injection.

(2) Maximum injection pressure. The director will approve a maximum injection pressure limit that:

(A) considers the risks of tensile failure and, where appropriate, geomechanical or other studies that assess the risk of tensile failure and shear failure;

(B) with a reasonable degree of certainty will avoid initiation or propagation of fractures in the confining zone or cause otherwise non-transmissive faults transecting the confining zone to become transmissive; and

(C) in no case may cause the movement of injection fluids or formation fluids in a manner that endangers USDWs.

(j) Plan for monitoring, sampling, and testing after initiation of operation.

(1) The applicant must submit a monitoring, sampling, and testing plan for verifying that the geologic storage facility is operating as permitted and that the injected fluids are confined to the injection zone.

(2) The plan must include the following:

(A) the analysis of the CO_2 stream prior to injection with sufficient frequency to yield data representative of its chemical and physical characteristics;

(B) the installation and use of continuous recording devices to monitor injection pressure, rate, temperature, and volume and/or mass, and the pressure on the annulus between the tubing and the long string casing, except during workovers;

(C) after initiation of injection, the performance on a quarterly [~~semi-annual~~] basis of corrosion monitoring of the well materials for loss of mass, thickness, cracking, pitting, and other signs of corrosion to ensure that the well components meet the minimum standards for material strength and performance set forth in subsection (e)(1)(A) of this section. The operator must report the results of such monitoring semi-annually [~~annually~~]. Corrosion monitoring may be accomplished by:

(i) analyzing coupons of the well construction materials in contact with the CO_2 stream;

(ii) routing the CO_2 stream through a loop constructed with the materials used in the well and inspecting the materials in the loop; or

(iii) using an alternative method, materials, or time period approved by the director;

(D) monitoring of geochemical and geophysical changes, including:

(i) periodic sampling of the fluid temperature, pH, conductivity, reservoir pressure and static fluid level of the injection zone and monitoring for pressure changes, and for changes in geochemistry, in a permeable and porous formation near to and above the top confining zone;

(ii) periodic monitoring of the quality and geochemistry of a USDW within the AOR and the formation fluid in a permeable and porous formation near to and above the top confining zone to detect any movement of the injected CO_2 through the confining zone into that monitored formation;

(iii) the location and number of monitoring wells justified on the basis of the AOR, injection rate and volume, geology, and the presence of artificial penetrations and other factors specific to the geologic storage facility; and

(iv) the monitoring frequency and spatial distribution of monitoring wells based on baseline geochemical data collected under subsection (c)(2) of this section and any modeling results in the AOR evaluation;

(E) tracking the extent of the CO_2 plume and the position of the pressure front by using indirect, geophysical techniques, which may include seismic, electrical, gravity, or electromagnetic surveys and/or down-hole CO_2 detection tools;

(F) a demonstration of external mechanical integrity pursuant to subsection (h)(2) of this section at least once per year until the injection well is plugged, and, if required by the director, a casing inspection log pursuant to requirements in subsection (h)(2) of this section at a frequency established in the testing and monitoring plan;

(G) [~~(F)~~] a [~~A~~] pressure fall-off test at least once every five years unless more frequent testing is required by the director based on site-specific information; and

(H) [~~(G)~~] additional monitoring as the director may determine to be necessary to support, upgrade, and improve computational modeling of the AOR evaluation and to determine compliance with the requirements that the injection activity not allow the movement of fluid containing any contaminant into USDWs and that the injected fluid remain within the permitted interval.

(k) Well plugging plan. The applicant must submit a well plugging plan for all injection wells and monitoring wells [~~**that penetrate the base of usable quality water**~~] that includes the following:

(1) a proposal for plugging all monitoring wells that penetrate the base of usable quality water and all injection wells upon abandonment in accordance with §3.14 of this title (relating to Plugging), in addition to the requirements of this section. The proposal must include:

(A) the type and number of plugs to be used;

(B) the placement of each plug, including the elevation of the top and bottom of each plug;

(C) the type, grade, and quantity of material to be used in plugging and information to demonstrate that the material is compatible with the CO_2 stream; and

(D) the method of placement of the plugs;

(2) proposals for activities to be undertaken prior to plugging an injection well, specifically:

(A) flushing each injection well with a buffer fluid;

(B) performing tests or measures to determine bottomhole reservoir pressure;

(C) performing final tests to assess mechanical integrity; and

(D) ensuring that the material to be used in plugging must be compatible with the CO_2 stream and the formation fluids;

(3) a proposal for giving notice of intent to plug monitoring wells that penetrate the base of usable quality water and all injection wells. The applicant's plan must ensure that:

(A) the operator notifies the director at least 60 days before plugging a well. At this time, if any changes have been made to the original well plugging plan, the operator must also provide a revised well plugging plan. At the discretion of the director, an operator may be allowed to proceed with well plugging on a shorter notice period; and

(B) the operator will file a notice of intention to plug and abandon (Form W-3A) a well with the appropriate Commission district office and the division in Austin at least five days prior to the beginning of plugging operations;

(4) a plugging report for monitoring wells that penetrate the base of usable quality water and all injection wells. The applicant's plan must ensure that within 30 days after plugging the operator will file a complete well plugging record (Form W-3) in duplicate with the appropriate district office. The operator and the person who performed the plugging operation (if other than the operator) must certify the report as accurate;

(5) a plan for plugging all monitoring wells that do not penetrate the base of usable quality water in accordance with 16 TAC Chapter 76 (relating to Water Well Drillers and Water Well Pump Installers); and

(6) a plan for certifying that all monitoring wells that do not penetrate the base of usable quality water will be plugged in accordance with 16 TAC Chapter 76.

(l) Emergency and remedial response plan. The applicant must submit an emergency and remedial response plan that:

(1) accounts for the entire AOR, regardless of whether or not corrective action in the AOR is phased;

(2) describes actions to be taken to address escape from the permitted injection interval or movement of the injection fluids or formation fluids that may cause an endangerment to USDWs during construction, operation, closure, and post-closure periods;

(3) includes a safety plan that includes:

(A) emergency response procedures;

(B) provisions to provide security against unauthorized activity;

(C) CO_2 release detection and prevention measures;

(D) instructions and procedures for alerting the general public and public safety personnel of the existence of an emergency;

(E) procedures for requesting assistance and for follow-up action to remove the public from an area of exposure;

(F) provisions for advance briefing of the public within the AOR on subjects such as the hazards and characteristics of CO_2,

(G) the manner in which the public will be notified of an emergency and steps to be taken in case of an emergency; and

(H) if necessary, proposed actions designed to minimize and respond to risks associated with potential seismic events, including seismic monitoring; and

(4) includes a description of the training and testing that will be provided to each employee at the storage facility on operational safety and emergency response procedures to the extent applicable to the employee's duties and responsibilities. The operator must train all employees before commencing injection and storage operations at the facility. The operator must train each subsequently hired employee before that employee commences work at the storage facility. The operator must hold a safety meeting with each contractor prior to the commencement of any new contract work at a storage facility. Emergency measures specific to the contractor's work must be explained in the contractor safety meeting. Training schedules, training dates, and course outlines must be provided to Commission personnel upon request for the purpose of Commission review to determine compliance with this paragraph.

(m) Post-injection storage facility care and closure plan. The applicant must submit a post-injection storage facility care and closure plan. The plan must include:

(1) a demonstration containing substantial evidence that the geologic storage project will no longer pose a risk of endangerment to USDWs at the end of the post-injection storage facility care timeframe. The demonstration must be based on significant, site-specific data and information, including all data and information collected pursuant subsections (b)-(d) of this section and §5.206(b)(5) of this title;

(2) the pressure differential between pre-injection and predicted post-injection pressures in the injection zone;

(3) the predicted position of the CO_2 plume and associated pressure front at closure as demonstrated in the AOR evaluation required under subsection (d) of this section;

(4) a description of the proposed post-injection monitoring location, methods, and frequency;

(5) a proposed schedule for submitting post-injection storage facility care monitoring results to the director;

(6) the estimated cost of proposed post-injection storage facility care and closure; and

(7) consideration and documentation of:

(A) the results of computational modeling performed pursuant to delineation of the AOR under subsection (d) of this section;

(B) the predicted timeframe for pressure decline within the injection zone, and any other zones, such that formation fluids may not be forced into any USDWs, and/or the timeframe for pressure decline to pre-injection pressures;

(C) the predicted rate of CO_2 plume migration within the injection zone, and the predicted timeframe for the stabilization of the CO_2 plume and associated pressure front;

(D) a description of the site-specific processes that will result in CO_2 trapping including immobilization by capillary trapping, dissolution, and mineralization at the site;

(E) the predicted rate of CO_2 trapping in the immobile capillary phase, dissolved phase, and/or mineral phase;

(F) the results of laboratory analyses, research studies, and/or field or site-specific studies to verify the information required in subparagraphs (D) and (E) of this paragraph;

(G) a characterization of the confining zone(s) including a demonstration that it is free of transmissive faults, fractures, and micro-fractures and of appropriate thickness, permeability, and integrity to impede fluid (e.g., CO_2, formation fluids) movement;

(H) the presence of potential conduits for fluid movement including planned injection wells and project monitoring wells associated with the proposed geologic storage project or any other projects in proximity to the predicted/modeled, final extent of the CO_2 plume and area of elevated pressure;

(I) a description of the well construction and an assessment of the quality of plugs of all abandoned wells within the AOR;

(J) the distance between the injection zone and the nearest USDWs above and/or below the injection zone; and

(K) any additional site-specific factors required by the director; and

(8) information submitted to support the demonstration in paragraph (1) of this subsection, which shall meet the following criteria:

(A) all analyses and tests performed to support the demonstration must be accurate, reproducible, and performed in accordance with the established quality assurance standards;

(B) estimation techniques must be appropriate and EPA-certified test protocols must be used where available;

(C) predictive models must be appropriate and tailored to the site conditions, composition of the CO_2 stream, and injection and site conditions over the life of the geologic storage project;

(D) predictive models must be calibrated using existing information (e.g., at Class I, Class II, or Class V experimental technology well sites) where sufficient data are available;

(E) reasonably conservative values and modeling assumptions must be used and disclosed to the director whenever values are estimated on the basis of known, historical information instead of site-specific measurements;

(F) an analysis must be performed to identify and assess aspects of the alternative post-injection storage facility care [~~PISC~~] timeframe demonstration that contribute significantly to uncertainty. The operator must conduct sensitivity analyses to determine the effect that significant uncertainty may contribute to the modeling demonstration;

(G) an approved quality assurance and quality control plan must address all aspects of the demonstration; and

(H) any additional criteria required by the director.

(n) Fees, financial responsibility, and financial assurance. The applicant must pay the fees, demonstrate that it has met the financial responsibility requirements, and provide the Commission with financial assurance as required under §5.205 of this title (relating to Fees, Financial Responsibility, and Financial Assurance).

(1) The applicant must demonstrate financial responsibility [~~and resources~~] for corrective action, injection well plugging, post-injection storage facility care and storage facility closure, and emergency and remedial response until the director has provided to the operator a written verification that the director has determined that the facility has reached the end of the post-injection storage facility care period.

(2) In determining whether the applicant is financially responsible, the director must rely on the following:

(A) the person's most recent audited annual report filed with the U. S. Securities and Exchange Commission under Section 13 or 15(d), Securities Exchange Act of 1934 (15 U.S.C. Section 78m or 78o(d)). The date of the audit may not be more than one year before the date of submission of the application to the division; and

(B) the person's most recent quarterly report filed with the U. S. Securities and Exchange Commission under Section 13 or 15(d), Securities Exchange Act of 1934 (15 U.S.C. Section 78m or 78o(d)); or

(C) if the person is not required to file such a report, the person's most recent audited financial statement. The date of the audit must not be more than one year before the date of submission of the application to the division.

(o) Letter from the Groundwater Advisory Unit of the Oil and Gas Division. The applicant must submit a letter from the Groundwater Advisory Unit of the Oil and Gas Division in accordance with Texas Water Code, §27.046.

(p) Other information. The applicant must submit any other information requested by the director as necessary to discharge the Commission's duties under Texas Water Code, Chapter 27, Subchapter B-1, or deemed necessary by the director to clarify, explain, and support the required attachments.

§5.204. Notice of Permit Actions and Public Comment Period.

(a) Notice requirements.

(1) The Commission shall give notice of the following actions:

(A) a draft permit has been prepared under §5.202(e) of this title (relating to Permit Required, and Draft Permit and Fact Sheet); and

(B) a hearing [~~that~~] has been scheduled under subsection (b)(2) of this section.

(2) General notice by publication. The Commission shall publish notice of a draft permit once a week for three consecutive weeks in a newspaper of general circulation in each county where the storage facility is located or is to be located. The Commission shall also post notice of a draft permit on the Commission's website.

(3) Methods of notification. The Commission shall give notice by the following methods:

(A) Individual notice. Notice of a draft permit or a public hearing shall be given by mailing a copy of the notice to the following persons:

(i) the applicant;

(ii) the **EPA** [~~United States Environmental Protection Agency~~];

(iii) the Texas Commission on Environmental Quality, the Texas Water Development Board, the Texas Department of State Health Services, the Texas Parks and Wildlife Department, the Texas General Land Office, the Texas Historical Commission, the United States Fish and Wildlife Service, other Federal and State agencies with jurisdiction over fish, shellfish, and wildlife resources, and coastal zone management plans, the Advisory Council on Historic Preservation, including any affected States (Indian Tribes) and any agency that the Commission knows has issued or is required to issue a permit for the same facility under any federal or state environmental program;

(iv) each adjoining mineral interest owner, other than the applicant, of the outermost boundary of the proposed geologic storage facility;

(v) each leaseholder and interest owner of minerals lying above or below the proposed geologic storage facility;

(vi) each adjoining leaseholder of minerals offsetting the outermost boundary of the proposed geologic storage facility;

(vii) each owner or leaseholder of any portion of the surface overlying the proposed geologic storage facility and the adjoining area of the outermost boundary of the proposed geologic storage facility;

(viii) the clerk of the county or counties where the proposed geologic storage facility is located or is proposed to be located;

(ix) the city clerk or other appropriate city official where the proposed geologic storage facility is located within city limits;

(x) any other unit of local government having jurisdiction over the area where the geologic storage facility is or is proposed to be located, and each state agency having any authority under state law with respect to the construction or operation of the geologic storage facility;

(xi) any State, Tribe, or Territory any portion of which is within the AOR of the Class VI project;

(xii) [~~(xi)~~] persons on the mailing list developed by the Commission, including those who request in writing to be on the list and by soliciting participants in public hearings in that area for their interest in being included on area mailing lists; and

(xiii) [~~(xii)~~] any other class of persons that the director determines should receive notice of the application.

(B) Any person otherwise entitled to receive notice under this paragraph may waive his or her rights to receive notice of a draft permit under this subsection.

(4) Content of notice. Individual notice must consist of:

(A) the applicant's intention to construct and operate an anthropogenic CO_2 geologic storage facility;

(B) a description of the geologic storage facility location;

(C) a copy of any draft permit and fact sheet;

(D) each physical location and the internet address at which a copy of the application may be inspected;

(E) a statement that:

(i) affected persons may protest**, and interested persons may request a hearing on,** the application;

(ii) protests **and requests for a hearing** must be filed in writing and must be mailed or delivered to Technical Permitting, Oil and Gas Division, Railroad Commission of Texas, P.O. Box 12967, Austin, Texas 78711; and

(iii) protests **and requests for a hearing** must be received by the director within 30 days of the date of receipt of the application by the division, receipt of individual notice, or last publication of notice, whichever is later; and

(F) information satisfying the requirements of 40 CFR §124.10(d)(1).

(5) Individual notice by publication. The applicant must make diligent efforts to ascertain the name and address of each person identified under paragraph (3)(A) of this subsection. The exercise of diligent efforts to ascertain the names and addresses of such persons requires an examination of county records where the facility is located and an investigation of any other information that is publicly and/or reasonably available to the applicant. If, after diligent efforts, an applicant has been unable to ascertain the name and address of one or more persons required to be notified under paragraph (3)(A) of this subsection, the applicant satisfies the notice requirements for those persons by the publication of the notice of application as required in paragraph (2) of this subsection. The applicant must submit an affidavit to the director specifying the efforts that the applicant took to identify each person whose name and/or address could not be ascertained.

(6) Notice to certain communities. The applicant shall identify whether any portions of the AOR encompass an Environmental Justice (EJ) or Limited English-Speaking Household community using the most recent U.S. Census Bureau American Community Survey data. If the AOR incudes an EJ or Limited English-Speaking Household community, the applicant shall conduct enhanced public outreach activities to these communities. Efforts to include EJ and Limited English-Speaking Household communities in public involvement activities in such cases shall include:

(A) published meeting notice in English and the identified language (e.g., Spanish);

(B) comment forms posted on the applicant's webpage and available at public meeting in English and the alternate language;

(C) interpretation services accommodated upon request;

(D) English translation of any comments made during any comment period in the alternate language; and

(E) to the extent possible, public meeting venues near public transportation.

(7) Comment period for a draft permit. Public notice of a draft permit, including a notice of intent to deny a permit application, shall allow at least 30 days for public comment.

(b) Public comment and hearing requirements.

(1) Public comment.

(A) During the public comment period, any interested person may submit written comments on the draft permit and may request a hearing if one has not already been scheduled.

(B) Reasonable limits may be set upon the time allowed for oral statements, and the submission of statements in writing may be required.

(C) The public comment period shall automatically be extended to the close of any public hearing under this section. The hearing examiner may also extend the comment period by so stating at the hearing.

(2) Public hearing.

(A) If the Commission receives a protest regarding an application for a new permit or for an amendment of an existing permit for a geologic storage facility from a person notified pursuant to subsection (a) of this section or from any other affected person within 30 days of the date of receipt of the application by the division, receipt of individual notice, or last publication of notice, whichever is later, then the director will notify the applicant that the director cannot administratively approve the application. Upon the written request of the applicant, the director will schedule a hearing on the application.

(B) The director shall hold a public hearing whenever the director finds, on the basis of requests, a significant degree of public interest in a draft permit.

(C) The director may also hold a public hearing at the director's discretion, whenever, for instance, such a hearing might clarify one or more issues involved in the permit decision.

(D) Public notice of a public hearing shall be given at least 30 days before the hearing. Public notice of a hearing may be given at the same time as public notice of the draft permit and the two notices may be combined.

(E) Upon the written request of the applicant, the Commission must give notice of a hearing to all affected persons, local governments, and other persons who express, in writing, an interest in the application. After the hearing, the examiner will recommend a final action by the Commission. Notices shall include information satisfying the requirements of 40 CFR §124.10(d)(2) and the Texas Government Code, §2001.052.

(3) If the Commission receives no protest regarding an application for a new permit or for the amendment of an existing permit for a geologic storage facility from a person notified pursuant to subsection (a) of this section or from any other affected person, the director may administratively approve the application.

(4) If the director administratively denies an application for a new permit or for the amendment of an existing permit for a geologic storage facility, upon the written request of the applicant, the director will schedule a hearing. After hearing, the examiner will recommend a final action by the Commission.

<u>(5) Upon making a final permit decision, the director shall issue a response to comments. The response shall specify which provisions, if any, of the draft permit have been changed in the final permit decision, and the reasons for the change, and shall briefly describe and respond to all significant comments on the draft permit raised during the public comment period or during any hearing. The Commission shall post the response to comments on the Commission's internet website.</u>

§5.205. Fees, Financial Responsibility, and Financial Assurance.

(a) Fees. In addition to the fee for each injection well required by §3.78 of this title (relating to Fees and Financial Security Requirements), the following non-refundable fees must be remitted to the Commission with the application:

(1) Base application fee.

(A) The applicant must pay to the Commission an application fee of $50,000 for each permit application for a geologic storage facility.

(B) The applicant must pay to the Commission an application fee of $25,000 for each application to amend a permit for a geologic storage facility.

(2) Injection fee. The operator must pay to the Commission an annual fee of $0.025 per metric ton of CO_2 injected into the geologic storage facility.

(3) Post-injection care fee. The operator must pay to the Commission an annual fee of $50,000 each year the operator does not inject into the geologic storage facility until the director has authorized storage facility closure.

(b) Financial responsibility.

(1) A person to whom a permit is issued under this subchapter must provide annually to the director evidence of financial responsibility that is satisfactory to the director. The **owner or** operator must demonstrate and maintain financial responsibility [~~and resources~~] for corrective action, injection well plugging, post-injection storage facility care and storage facility closure, and emergency and remedial response until the director has provided written verification that the director has determined that the facility has reached the end of the post-injection storage facility care period.

(2) In determining whether the person is financially responsible, the director must rely on:

(A) the person's most recent audited annual report filed with the U. S. Securities and Exchange Commission under Section 13 or 15(d), Securities Exchange Act of 1934 (15 U.S.C. Section 78m or 78o(d)); and

(B) the person's most recent quarterly report filed with the U. S. Securities and Exchange Commission under Section 13 or 15(d), Securities Exchange Act of 1934 (15 U.S.C. Section 78m or 78o(d)); or

(C) if the person is not required to file such a report, the person's most recent audited financial statement. The date of the audit must not be more than one year before the date of submission of the application to the director.

(3) The applicant's demonstration of financial responsibility must account for the entire AOR, regardless of whether corrective action in the AOR is phased.

(c) Financial assurance. The director shall consider and approve the applicant's demonstration of financial responsibility for all the phases of the geologic sequestration project, including the post-injection storage facility care and closure phase and the plugging phase, prior to issuance of a geologic storage injection well permit.

(1) Injection and monitoring wells. The **owner or** operator must comply with the requirements of §3.78 of this title for all monitoring wells that penetrate the base of usable quality water and this subsection for all injection wells.

(2) Geologic storage facility.

(A) The applicant must include in an application for a geologic storage facility permit:

(i) a **detailed** written estimate**, in current dollars,** of the **cost** [~~highest likely dollar amount~~] necessary to perform **corrective action on wells in the area of review, plugging of injection wells,** post-injection monitoring and closure of the facility**, and emergency and remedial response** that shows all assumptions and calculations used to develop the estimate;

(ii) a copy of the form of the bond or letter of credit that will be filed with the Commission; and

(iii) information concerning the issuer of the bond or letter of credit including the issuer's name and address and evidence of authority to issue bonds or letters of credit in Texas.

(B) A geologic storage facility shall not receive CO_2 until a bond or letter of credit in an amount approved by the director under this subsection and meeting the requirements of this subsection as to form and issuer has been filed with and approved by the director.

(C) The determination of the amount of financial assurance for a geologic storage facility is subject to the following requirements:

(i) The director must approve the dollar amount of the financial assurance. The amount of financial assurance required to be filed under this subsection must be equal to or greater than the maximum amount necessary to perform corrective action, emergency response, and remedial action, post-injection monitoring and site care, and closure of the geologic storage facility, including plugging of wells, at any time during the permit term in accordance with all applicable state laws, Commission rules and orders, and the permit. The cost estimate must be performed for each phase separately and must be based on the costs to the Commission of hiring a third party to perform the required activities. A third party is a party who is not within the corporate structure of the owner or operator;

(ii) A qualified professional engineer licensed by the State of Texas, as required under Occupations Code, Chapter 1001, relating to Texas Engineering Practice Act, must prepare or supervise the preparation of a written estimate of the highest likely amount necessary to close the geologic storage facility. The **owner or** operator must submit to the director the written estimate under seal of a qualified licensed professional engineer, as required under Occupations Code, Chapter 1001, relating to Texas Engineering Practice Act; and

(iii) The Commission may use the proceeds of financial assurance filed under this subsection to pay the costs of plugging any well or wells at the facility if the financial assurance for plugging costs filed with the Commission is insufficient to pay for the plugging of such well or wells.

(D) Bonds and letters of credit filed in satisfaction of the financial assurance requirements for a geologic storage facility must comply with the following standards as to issuer and form.

(i) The issuer of any geologic storage facility bond filed in satisfaction of the requirements of this subsection must be a corporate surety authorized to do business in Texas. The form of bond filed under this subsection must provide that the bond be renewed and continued in effect until the conditions of the bond have been met or its release is authorized by the director.

(ii) Any letter of credit filed in satisfaction of the requirements of this subsection must be issued by and drawn on a bank authorized under state or federal law to operate in Texas. The letter of credit must be an irrevocable, standby letter of credit subject to the requirements of Texas Business and Commerce Code, §§5.101 - 5.118. The letter of credit must provide that it will be renewed and continued in effect until the conditions of the letter of credit have been met or its release is authorized by the director.

(iii) The qualifying financial responsibility instruments must comprise protective conditions of coverage. Protective conditions of coverage must include at a minimum cancellation, renewal, and continuation provisions; specifications on when the provider becomes liable following a notice of cancellation if there is a failure to renew with a new qualifying financial instrument; and requirements for the provider to meet a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.

(I) Cancellation. An **owner or** operator must provide that its financial instrument may not cancel, terminate, or fail to renew except for failure to pay such financial instrument. If there is a failure to pay the financial instrument, the financial institution may elect to cancel, terminate, or fail to renew the instrument by sending notice by certified mail to the **owner or** operator and the director. The cancellation must not be final until at least 120 days after the Commission receives the cancellation notice. The **owner or** operator must provide an alternate financial responsibility demonstration within 60 days of notice of cancellation, and if an alternate financial responsibility demonstration is not acceptable or possible, any funds from the instrument being cancelled must be released within 60 days of notification by the director.

(II) Renewal. If a financial instrument expires, the **owner or** operator must renew the financial instrument for the entire term of the geologic storage project. The instrument may be automatically renewed as long as the operator has the option of renewal at the face amount of the expiring instrument. The automatic renewal of the instrument must, at a minimum, provide the holder with the option of renewal at the face amount of the expiring financial instrument.

(III) Financial instrument to remain in effect. Cancellation, termination, or failure to renew shall not occur and the financial instrument shall remain in full force and effect if on or before the date of expiration:

(-a-) the director deems the facility abandoned;

(-b-) the permit is terminated or revoked or a new permit is denied;

(-c-) closure is ordered by the director or a United States district court or other court of competent jurisdiction;

(-d-) the **owner or** operator is named as debtor in a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code; or

(-e-) the amount due is paid.

(E) During the active life of the geologic storage project, the **owner or** operator must adjust the cost estimate for inflation within 60 days prior to the anniversary date of the establishment of the financial instruments used to comply with paragraph (2)(C)(i) of this subsection and provide this adjustment to the director. The **owner or** operator must also provide to the director written updates of adjustments to the cost estimate within 60 days of any amendments to the area of review and corrective action plan, the injection well plugging plan, the post-injection storage facility care and closure plan, and the emergency and remedial response plan.

(F) [~~(E)~~] The **owner or** operator of a geologic storage facility must provide to the director, and the director must approve, annual written updates of the cost estimate to increase or decrease the cost estimate to account for any changes to the AOR and corrective action plan, the emergency response and remedial action plan, the injection well plugging plan, and the post-injection storage facility care and closure plan. The Director must approve any decrease or increase to the initial cost estimate. During the active life of the geologic storage project, the **owner or** operator must revise the cost estimate no later than 60 days after the director has approved the request to modify the AOR and corrective action plan, the injection well plugging plan, the post-injection storage facility care and closure plan, and the emergency and response plan, if a change in any of these plans increases the cost. If a change to a plan decreases the cost, any withdrawal of funds must be approved by the director. Any decrease to the value of a financial assurance instrument must first be approved by the director. The revised cost estimate must be adjusted for inflation as specified at paragraph (2)(E) of this subsection. The **owner or** operator must provide to the director, within 60 days of notification by the director, [~~upon request~~] an adjustment of the cost estimate if the director determines during the annual evaluation of the qualifying financial responsibility instruments that the most recent [~~has reason to believe that the original~~] demonstration is no longer adequate to cover the cost of corrective action, injection well plugging and post-injection storage facility care and closure, and emergency and remedial response.

(G) Whenever the current cost estimate increases to an amount greater than the face amount of a financial instrument currently in use, the **owner or** operator, within 60 days after the increase, must either cause the face amount to be increased to an amount at least equal to the current cost estimate and submit evidence of such increase to the director or obtain other financial responsibility instruments to cover the increase. Whenever the current cost estimate decreases, the face amount of the financial assurance instrument may be reduced to the amount of the current cost estimate only after the operator has received written approval from the director.

(H) The requirement to maintain adequate financial responsibility is directly enforceable regardless of whether the requirement is a condition of the permit.

(i) The **owner or** operator must maintain financial responsibility until:

(I) the director receives and approves the completed post-injection storage facility care and closure plan; and

(II) **the director issues the certificate of closure**.

(ii) The **owner or** operator may be released from a financial instrument in the following circumstances:

(I) The **owner or** operator has completed the phase of the geologic storage project for which the financial instrument was required and has fulfilled all its financial obligations as determined by the director, including obtaining financial responsibility for the next phase of the geologic storage project, if required; or

(II) The **owner or** operator has submitted a replacement financial instrument and received written approval from the director accepting the new financial instrument and releasing the **owner or** operator from the previous financial instrument.

(3) The director may consider allowing the phasing in of financial assurance for only corrective action based on project-specific factors.

(4) The director may approve a reduction in the amount of financial assurance required for post-injection monitoring and/or corrective action based on project-specific monitoring results.

(5) The **owner or** operator must maintain the required financial responsibility regardless of the status of the director's review of the financial responsibility demonstration.

(d) Notice of adverse financial conditions.

(1) The **owner or** operator must notify the Commission of adverse financial conditions that may affect the **owner's or** operator's ability to carry out injection well plugging and post-injection storage facility care and closure. An **owner or** operator must file any notice of bankruptcy in accordance with §3.1(f) of this title (relating to Organization Report; Retention of Records; Notice Requirements). The **owner or** operator must give such notice by certified mail.

(2) The **owner or** operator filing a bond must ensure that the bond provides a mechanism for the bond or surety company to give prompt notice to the Commission and the **owner or** operator of any action filed alleging insolvency or bankruptcy of the surety company or the bank or alleging any violation that would result in suspension or revocation of the surety or bank's charter or license to do business.

(3) Upon the incapacity of a bank or surety company by reason of bankruptcy, insolvency or suspension, or revocation of its charter or license, the Commission must deem the **owner or** operator to be without bond coverage. The Commission must issue a notice to any **owner or** operator who is without bond coverage and must specify a reasonable period to replace bond coverage, not to exceed 60 days.

§5.206. Permit Standards.

(a) General permit conditions.

(1) Each condition applicable to a permit shall be incorporated into the permit either expressly or by reference. If incorporated by reference, a specific citation to the rules in this chapter shall be given in the permit. The requirements listed in this section are directly enforceable regardless of whether the requirement is a condition of the permit.

(2) The permit may be modified, revoked and reissued, or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.

(b) General criteria. The director may issue a permit under this subchapter if the applicant demonstrates and the director finds that:

(1) the injection and geologic storage of anthropogenic CO_2 will not endanger or injure any existing or prospective oil, gas, geothermal, or other mineral resource, or cause waste as defined by Texas Natural Resources Code, §85.046(11);

(2) with proper safeguards, both USDWs and surface water can be adequately protected from CO_2 migration or displaced formation fluids;

(3) the injection of anthropogenic CO_2 will not endanger or injure human health and safety;

(4) the construction, operation, maintenance, conversion, plugging, abandonment, or any other injection activity does not allow the movement of fluid containing any contaminant into USDWs, if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR Part 142 or may otherwise adversely affect the health of persons;

(5) [~~(4)~~] the reservoir into which the anthropogenic CO_2 is injected is suitable for or capable of being made suitable for protecting against the escape or migration of anthropogenic CO_2 from the storage reservoir;

(6) [~~(5)~~] the geologic storage facility will be sited in an area with suitable geology, which at a minimum must include:

(A) an injection zone of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the CO_2 stream; and

(B) a confining zone that is laterally continuous and free of known transecting transmissive faults or fractures over an area sufficient to contain the injected CO_2 stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without compromising the confining zone or causing the movement of fluids that endangers USDWs;

(7) [~~(6)~~] the applicant for the permit meets all of the other statutory and regulatory requirements for the issuance of the permit;

(8) [~~(7)~~] the applicant has provided a letter from the Groundwater Advisory Unit of the Oil and Gas Division in accordance with §5.203(o) of this title (relating to Application Requirements);

(9) [~~(8)~~] the applicant has provided a letter of determination from TCEQ concluding that drilling and operating an anthropogenic CO_2 injection well for geologic storage or constructing or operating a geologic storage facility will not impact or interfere with any previous or existing Class I injection well, including any associated waste plume, or any other injection well authorized or permitted by TCEQ;

(10) [~~(9)~~] the applicant has provided a signed statement that the applicant has a good faith claim to the necessary and sufficient property rights for construction and operation of the geologic storage facility for at least the first five years after initiation of injection in accordance with §5.203(d)(1)(A) of this title;

(11) [~~(10~~] the applicant has paid the fees required in §5.205(a) of this title (relating to Fees, Financial Responsibility, and Financial Assurance);

(12) [~~(11)~~] the director has determined that the applicant has sufficiently demonstrated financial responsibility as required in §5.205(b) of this title; and

(13) [~~(12)~~] the applicant submitted to the director financial assurance in accordance with §5.205(c) of this title.

(c) Permit conditions for injection [~~Injection~~] well construction.

(1) Construction of anthropogenic CO_2 injection wells must meet the criteria in §5.203(e) of this title.

(2) Within 30 days after the completion or conversion of an injection well subject to this subchapter, the operator must file with the division a complete record of the well on Commission Form W-2, Oil Well Potential Test, Completion or Recompletion Report and Log [~~the appropriate form~~] showing the current completion.

(3) Except in the case of an emergency repair, the operator of a geologic storage facility must notify the director in writing at least 30 days prior to conducting any well workover that involves running tubing and setting packers, beginning any workover or remedial operation, or conducting any required pressure tests or surveys. Such activities shall not commence before the end of the 30 days unless authorized by the director. In the case of an emergency repair, the operator must notify the director of such emergency repair as soon as reasonably practical.

(d) Permit conditions for operating [~~Operating~~] a geologic storage facility.

(1) Operating plan.

(A) The operator must maintain and comply with the approved operating plan.

(B) Prior to approval for the operation of a Class VI injection well, the operator shall submit, and the director shall consider, the following information:

(i) the final AOR based on modeling, using data obtained during logging and testing of the well and the formation as required by clauses **(ii), (iii), (iv), (vi), (vii), and (x)** of this subparagraph;

(ii) any relevant updates, based on data obtained during logging and testing of the well and the formation as required by clauses **(iii), (iv), (vi), (vii), and (x) of this subparagraph** to the information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, submitted to satisfy the requirements of **§5.203(c)(2) and (3) of this title**;

(iii) information on the compatibility of the CO_2 stream with fluids in the injection zones and minerals in both the injection and the confining zones, based on the results of the formation testing program, and with the materials used to construct the well;

(iv) the results of the formation testing program required by §5.203(f) of this title;

(v) final injection well construction procedures that meet the requirements of §5.203(e) of this title;

(vi) the status of corrective action on wells in the AOR;

(vii) all available logging and testing program data on the well required by §5.203(f) of this title;

(viii) a demonstration of mechanical integrity pursuant to §5.203(h) of this title;

(ix) any updates to the proposed AOR and corrective action plan, testing and monitoring plan, injection well plugging plan, post-injection storage facility care and closure plan, or the emergency and remedial response plan submitted under §5.203(m) of this subchapter, which are necessary to address new information collected during logging and testing of the well and the formation as required by this section, and any updates to the alternative post-injection storage facility care timeframe demonstration submitted under §5.203(m) of this title, which are necessary to address new information collected during the logging and testing of the well and the formation as required by this section; and

(x) any other information requested by the director.

(2) Operating criteria.

(A) Injection between the outermost casing protecting USDWs and the well bore is prohibited.

(B) The total volume of CO_2 injected into the storage facility must be metered through a master meter or a series of master meters. The volume and/or mass of CO_2 injected into each injection well must be metered through an individual well meter. If mass is determined using volume, the operator must provide calculations.

(C) The operator must comply with a maximum surface injection pressure limit approved by the director and specified in the permit. In approving a maximum surface injection pressure limit, the director must consider the results of well tests and, where appropriate, geomechanical or other studies that assess the risks of tensile failure and shear failure. The director must approve limits that, with a reasonable degree of certainty, will avoid initiation or propagation of fractures in the confining zone or cause otherwise non-transmissive faults or fractures transecting the confining zone to become transmissive. In no case may injection pressure cause movement of injection fluids or formation fluids in a manner that endangers USDWs. The Commission shall include in any permit it might issue a limit of 90 percent of the fracture pressure to ensure that the injection pressure does not initiate new fractures or propagate existing fractures in the injection zone(s). In no case may injection pressure initiate fractures in the confining zone(s) or cause the movement of injection or formation fluids that endangers a USDW. The director may approve a plan for controlled artificial fracturing of the injection zone.

(D) The operator must fill the annulus between the tubing and the long string casing with a corrosion inhibiting fluid approved by the director. The owner or operator must maintain on the annulus a pressure that exceeds the operating injection pressure, unless the director determines that such requirement might harm the integrity of the well or endanger USDWs.

(E) The operator must install and use continuous recording devices to monitor the injection pressure, and the rate, volume, and temperature of the CO_2 stream. The operator must monitor the pressure on the annulus between the tubing and the long string casing. The operator must continuously record, continuously monitor, or control by a preset high-low pressure sensor switch the wellhead pressure of each injection well.

(F) The operator must comply with the following requirements for alarms and automatic shut-off systems.

(i) The operator must install and use alarms and automatic shut-off systems designed to alert the operator and shut-in the well when operating parameters such as annulus pressure, injection rate or other parameters diverge from permitted ranges and/or gradients. On offshore wells, the automatic shut-off systems must be installed down-hole.

(ii) If an automatic shutdown is triggered or a loss of mechanical integrity is discovered, the operator must immediately investigate and identify as expeditiously as possible the cause. If, upon investigation, the well appears to be lacking mechanical integrity, or if monitoring otherwise indicates that the well may be lacking mechanical integrity, the operator must:

(I) immediately cease injection;

(II) take all steps reasonably necessary to determine whether there may have been a release of the injected CO_2 stream into any unauthorized zone;

(III) notify the director as soon as practicable, but within 24 hours;

(IV) restore and demonstrate mechanical integrity to the satisfaction of the director prior to resuming injection; and

(V) notify the director when injection can be expected to resume.

(e) Permit conditions for monitoring [~~Monitoring~~], sampling, and testing requirements.

(1) The operator of an anthropogenic CO_2 injection well must maintain and comply with the approved monitoring, sampling, and testing plan to verify that the geologic storage facility is operating as permitted and that the injected fluids are confined to the injection zone.

(2) All permits shall include the following requirements:

(A) the proper use, maintenance, and installation of monitoring equipment or methods;

(B) monitoring including type, intervals, and frequency sufficient to yield data that are representative of the monitored activity including, when required, continuous monitoring;

(C) reporting no less frequently than as specified in §5.207 of this title (relating to Reporting and Record-Keeping).

(3) The director may require additional monitoring as necessary to support, upgrade, and improve computational modeling of the AOR evaluation and to determine compliance with the requirement that the injection activity not allow movement of fluid that would endanger USDWs.

(4) The director may require measures and actions designed to minimize and respond to risks associated with potential seismic events, including seismic monitoring.

(5) The operator shall comply with the following monitoring and record retention requirements.

(A) Samples and measurements taken for the purpose of monitoring shall be representative of the monitored activity.

(B) The permittee shall retain records of all monitoring information, including the following:

(i) calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, copies of all reports required by the permit, and records of all data used to complete the permit application, for a period of at least **ten** years from the date of the sample, measurement, report, or application. This period may be extended by the director at any time; and

(ii) the nature and composition of all injected fluids until **ten** years after the completion of any plugging and abandonment **procedures specified in §5.203(k)(2) of this title for** the injection well**s**. The director may require the operator to submit the records to the director at the conclusion of the retention period. **This period may be extended by the director at any time**.

(C) Records of monitoring information shall include:

(i) the date, exact place, and time of sampling or measurements;

(ii) the individuals who performed the sampling or measurements;

(iii) the dates analyses were performed;

(iv) the individuals who performed the analyses;

(v) the analytical techniques or methods used; and

(vi) the results of such analyses.

(D) Operators of Class VI wells shall retain records as specified in this subchapter.

(f) Permit conditions for mechanical [~~Mechanical~~] integrity.

(1) The operator must maintain and comply with the approved mechanical integrity testing plan submitted in accordance with §5.203(j) of this title.

(2) The operator must establish mechanical integrity prior to commencing injection. Thereafter, other [~~Other~~] than during periods of well workover in which the sealed tubing-casing annulus is of necessity disassembled for maintenance or corrective procedures, the operator must maintain mechanical integrity of the injection well at all times.

(3) If the director determines that the injection well lacks mechanical integrity, the director shall give written notice of the director's determination to the operator. Unless the director requires immediate cessation, the operator shall cease injection into the well within 48 hours of receipt of the director's determination. The director may allow plugging of the well or require the permittee to perform such additional construction, operation, monitoring, reporting and corrective action as is necessary to prevent the movement of fluid into or between USDWs caused by the lack of mechanical integrity. The operator may resume injection upon written notification of the director's determination that the operator has demonstrated the well has mechanical integrity.

[~~(3) The operator must either repair and successfully retest or plug a well that fails a mechanical integrity test.~~]

(4) **The operator must either repair and successfully retest or plug a well that fails a mechanical integrity test. However, t**he director may allow the operator of a well which lacks internal mechanical integrity **because there is a leak in the casing, tubing, or packer** to continue or resume injection if the operator has made a satisfactory demonstration that there is no movement of fluid into or between USDWs.

(5) [~~(4)~~] The director may require additional or alternative tests if the results presented by the operator do not demonstrate to the director that there is no significant leak in the casing, tubing, or packer or movement of fluid into or between formations containing USDWs resulting from the injection activity.

(g) Permit conditions for AOR and corrective action. At [~~Notwithstanding the requirement in §5.203(d)(2)(B)(i) of this title to perform a re-evaluation of the AOR, at~~] the frequency specified in the approved AOR and corrective action plan or permit, and [~~the operator of a geologic storage facility also must conduct the following~~] whenever warranted by a material change in the monitoring and/or operational data or in the evaluation of the monitoring and operational data by the operator, but no less frequently than every five years, the operator of a geologic storage facility also must:

(1) perform a re-evaluation of the AOR by performing all of the actions specified in §5.203(d)(1)(A) - (C) of this title to delineate the AOR [~~**and identify all wells that require corrective action**~~];

(2) identify all wells in the re-evaluated AOR that require corrective action;

(3) perform corrective action on wells requiring corrective action in the re-evaluated AOR in the same manner specified in §5.203(d)(1)(C) of this title; [~~and~~]

(4) submit an amended AOR and corrective action plan or demonstrate to the director through monitoring data and modeling results that no change to the AOR and corrective action plan is needed. Any amendments to the AOR and corrective action plan must be approved by the director, must be incorporated into the permit, and are subject to the permit modification requirements at §5.202 of this title (relating to Permit Required, and Draft Permit and Fact Sheet), as applicable; and

(5) retain all modeling inputs and data used to support AOR reevaluations for at least 10 years.

(h) Permit conditions for emergency [~~Emergency~~], mitigation, and remedial response.

(1) Plan. The operator must maintain and comply with the approved emergency and remedial response plan required by §5.203(l) of this title. The operator must update the plan in accordance with §5.207(a)(2)(D)(vi) of this title (relating to Reporting and Record-Keeping). The operator must make copies of the plan available at the storage facility and at the company headquarters. The emergency and remedial response plan and the demonstration of financial responsibility must account for the AOR delineated as specified in §5.203(d)(1)(A) - (C) of this title or the most recently evaluated AOR delineated under subsection (g) of this section, regardless of whether or not corrective action in the AOR is phased.

(2) Training.

(A) The operator must prepare and implement a plan to train and test each employee at the storage facility on occupational safety and emergency response procedures to the extent applicable to the employee's duties and responsibilities. The operator must make copies of the plan available at the geological storage facility. The operator must train all employees before commencing injection and storage operations at the facility. The operator must train each subsequently hired employee before that employee commences work at the storage facility.

(B) The operator must hold a safety meeting with each contractor prior to the commencement of any new contract work at a storage facility. The operator must explain emergency measures specific to the contractor's work in the contractor safety meeting.

(C) The operator must provide training schedules, training dates, and course outlines to Commission personnel annually and upon request for the purpose of Commission review to determine compliance with this paragraph.

(3) Action.

(A) If an operator obtains evidence that the injected CO_2 stream and associated pressure front may cause an endangerment to USDWs, the operator must:

(i) [~~(A)~~] immediately cease injection;

(ii) [~~(B)~~] take all steps reasonably necessary to identify and characterize any release;

(iii) [~~(C)~~] notify the director as soon as practicable but within at least 24 hours; and

(iv) [~~(D)~~] implement the approved emergency and remedial response plan.

(B) If any water quality monitoring of a USDW indicates the movement of any contaminant into the USDW, except as authorized by an aquifer exemption, the director shall prescribe such additional requirements for construction, corrective action, operation, monitoring, or reporting, including plugging of the injection well, as are necessary to prevent such movement.

(4) Resumption of injection. The director may allow the operator to resume injection prior to remediation if the operator demonstrates that the injection operation will not endanger USDWs.

(i) Permit conditions for Commission witnessing of testing and logging. The operator must provide the division with the opportunity to witness all planned well workovers, stimulation activities, other than stimulation for formation testing, and testing and logging. The operator must submit a proposed schedule of such activities to the Commission at least 30 days prior to conducting the first such activity and submit notice at least 48 hours in advance of any actual activity. Such activities shall not commence before the end of the 30 days unless authorized by the director.

(j) Permit conditions for well [~~Well~~] plugging. The operator of a geologic storage facility must maintain and comply with the approved well plugging plan required by §5.203(k) of this title.

(k) Permit conditions for post-injection [~~Post-injection~~] storage facility care and closure.

(1) Post-injection storage facility care and closure plan.

(A) The operator of an injection well must maintain and comply with the approved post-injection storage facility care and closure plan.

(B) The operator must update the plan in accordance with §5.207(a)(2)(D)(vi) of this title. At any time during the life of the geologic sequestration project, the operator may modify and resubmit the post-injection site care and site closure plan for the director's approval within 30 days of such change. Any amendments to the post-injection site care and site closure plan must be approved by the director, be incorporated into the permit, and are subject to the permit modification requirements in §5.202 of this title [~~(relating to Permit Required)~~], as appropriate.

(C) Upon cessation of injection, the operator of a geologic storage facility must either submit an amended plan or demonstrate to the director through monitoring data and modeling results that no amendment to the plan is needed.

(2) Post-injection storage facility monitoring. Following cessation of injection, the operator must continue to conduct monitoring as specified in the approved plan until the director determines that the position of the CO_2 plume and pressure front are such that the geologic storage facility will not endanger USDWs.

(3) Prior to closure. Prior to authorization for storage facility closure, the operator must demonstrate to the director, based on monitoring, other site-specific data, and modeling that is reasonably consistent with site performance that no additional monitoring is needed to assure that the geologic storage

facility will not endanger USDWs. The operator must demonstrate, based on the current understanding of the site, including monitoring data and/or modeling, all of the following:

(A) the estimated magnitude and extent of the facility footprint (the CO_2 plume and the area of elevated pressure);

(B) that there is no leakage of either CO_2 or displaced formation fluids that will endanger USDWs;

(C) that the injected or displaced fluids are not expected to migrate in the future in a manner that encounters a potential leakage pathway into USDWs;

(D) that the injection wells at the site completed into or through the injection zone or confining zone will be plugged and abandoned in accordance with these requirements; and

(E) any remaining facility monitoring wells will be properly plugged or are being managed by a person and in a manner approved by the director.

(4) Notice of intent for storage facility closure. The operator must notify the director in writing at least 120 days before storage facility closure. At the time of such notice, if the operator has made any changes to the original plan, the operator also must provide the revised plan. The director may approve a shorter notice period.

(5) Authorization for storage facility closure. No operator may initiate storage facility closure until the director has approved closure of the storage facility in writing. After the director has authorized storage facility closure, the operator must plug all wells in accordance with the approved plan required by §5.203(k) of this title <u>and submit a plugging record (Form W-3) as required by §3.14 of this title (relating to Plugging)</u>.

(6) Storage facility closure report. Once the director has authorized storage facility closure, the operator must submit a storage facility closure report within 90 days that must thereafter be retained by the Commission in Austin. The report must include the following information:

(A) documentation of appropriate injection and monitoring well plugging. The operator must provide a copy of a survey plat that has been submitted to the Regional Administrator of Region 6 of the <u>**EPA**</u> [~~United States Environmental Protection Agency~~]. The plat must indicate the location of the injection well relative to permanently surveyed benchmarks including the Latitude/Longitude or X/Y coordinates of the surface location in the NAD 27, NAD 83, or WGS 84 coordinate system, a labeled scale bar, and northerly direction arrow;

(B) documentation of appropriate notification and information to such state and local authorities as have authority over drilling activities to enable such state and local authorities to impose appropriate conditions on subsequent drilling activities that may penetrate the injection and confining zones; and

(C) records reflecting the nature, composition, volume and mass of the CO_2 stream. If mass is determined using volume, the operator must provide calculations.

(7) Certificate of closure. Upon completion of the requirements in paragraphs (3) - (6) of this subsection, the director will issue a certificate of closure. At that time, the operator is released from the requirement in §5.205(c) of this title to maintain financial assurance.

(l) Permit conditions for deed [~~Deed~~] notation. The operator of a geologic storage facility must record a notation on the deed to the facility property; on any other document that is normally examined during title search; or on any other document that is acceptable to the county clerk for filing in the official public records of the county that will in perpetuity provide any potential purchaser of the property the following information:

(1) a complete legal description of the affected property;

(2) that land has been used to geologically store CO_2;

(3) that the survey plat has been filed with the Commission;

(4) the address of the office of the United States Environmental Protection Agency, Region 6, to which the operator sent a copy of the survey plat; and

(5) the volume and mass of fluid injected, the injection zone or zones into which it was injected, and the period over which injection occurred. If mass is determined using volume, the operator must provide calculations.

(m) Permit conditions for retention [~~Retention~~] of records. The permittee shall retain records **as follows.**

(1) All modeling inputs and data used to support area of review reevaluations under subsection (e) of this section shall be retained for 10 years.

(2) The permittee shall retain records as follows:

(A) All data collected under §5.203 of this title for Class VI permit applications shall be retained throughout the life of the geologic storage project and for 10 years following site closure.

(B) Data on the nature and composition of all injected fluids collected pursuant to §5.203(i)(1)(D) of this title shall be retained until 10 years following site closure. The director may require the operator to submit the records to the director at the conclusion of the retention period.

(C) Monitoring data collected pursuant to §5.203(j)(2) of this title shall be retained for 10 years after it is collected.

(D) Well plugging reports, post-injection site care data, including data and information used to develop the demonstration of the alternative post-injection site care timeframe, and the site closure report collected pursuant to requirements of subsection (k)(6) of this section and paragraph (4) of this subsection shall be retained for 10 years following site closure.

(E) The director has authority to require the operator to retain any records required in this subchapter for longer than 10 years following site closure.

(3) Within 60 days after plugging, the operator must submit, pursuant to §5.207(b)(2) of this title, a plugging report to the director. The report must be certified as accurate by the operator and

by the person who performed the plugging operation (if other than the operator.) The operator shall retain the well plugging report for 10 years following site closure.

(4) The operator must submit a site closure report to the director within 90 days of site closure, which must thereafter be retained at a location designated by the director for 10 years following site closure. The report must include:

(A) documentation of appropriate injection and monitoring well plugging as specified in §5.203(k) of this title. The operator must provide a copy of a survey plat which has been submitted to the local zoning authority designated by the director. The plat must indicate the location of the injection well relative to permanently surveyed benchmarks. The operator must also submit a copy of the plat to the Regional Administrator of the appropriate EPA Regional Office; and

(B) documentation of appropriate notification and information to such State, local and Tribal authorities that have authority over drilling activities to enable such State, local, and Tribal authorities to impose appropriate conditions on subsequent drilling activities that may penetrate the injection and confining zone(s); and

(5) Records reflecting the nature, composition, and volume of the CO_2 plume shall be retained for 10 years following site closure.

~~of all monitoring information, including the following:~~

~~(A) calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, copies of all reports required by this permit, and records of all data used to complete the application for this permit, for a period of at least three years from the date of the sample, measurement, report, or application. This period may be extended by the director at any time; and~~

~~(B) the nature and composition of all injected fluids until three years after the completion of any plugging and abandonment procedures. The director may require the operator to submit the records to the director at the conclusion of the retention period.~~

~~(2) Records of monitoring information shall include:~~

~~(A) the date, exact place, and time of sampling or measurements;~~

~~(B) the individuals who performed the sampling or measurements;~~

~~(C) the dates analyses were performed;~~

~~(D) the individuals who performed the analyses;~~

~~(E) the analytical techniques or methods used; and~~

~~(F) the results of such analyses.~~

<u>(3)</u> The operator must retain for 10 years following storage facility closure records collected <u>to prepare the permit application, data on the nature and composition of all injected fluids, and records collected</u> during the post-injection storage facility care period. The operator must <u>submit</u> [~~deliver~~] the records to

the director at the conclusion of the retention period, and the records must thereafter be retained at the Austin headquarters of the Commission.

(n) <u>Permit conditions for signs</u> [~~Signs~~]. The operator must identify each location at which geologic storage activities take place, including each injection well, by a sign that meets the requirements specified in §3.3(1), (2), and (5) of this title (relating to Identification of Properties, Wells, and Tanks). In addition, each sign must include a telephone number where the operator or a representative of the operator can be reached 24 hours a day, seven days a week in the event of an emergency.

(o) Other permit terms and conditions.

(1) Protection of USDWs. In any permit for a geologic storage facility, the director must impose terms and conditions reasonably necessary to protect USDWs. <u>Permits issued under this subchapter shall be issued for the operating life of the facility and the post-injection storage facility care period. The director shall review each permit at least once every five years to determine whether it should be modified, revoked and reissued, or terminated.</u> Permits issued under this subchapter continue in effect until revoked, modified, or terminated by the Commission. The operator must comply with each requirement set forth in this subchapter as a condition of the permit unless modified by the terms of the permit.

(2) Other conditions. The following conditions shall also be included in any permit issued under this subchapter.

(A) Duty to comply. The permittee must comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the Safe Drinking Water Act and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application. However, the permittee need not comply with the provisions of the permit to the extent and for the duration such noncompliance is authorized in an emergency permit under 40 CFR §144.34.

(B) Need to halt or reduce activity not a defense. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

(C) Duty to mitigate. The permittee shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this permit.

(D) Proper operation and maintenance. The permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the permittee to achieve compliance with the conditions of this permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of the permit.

(E) Property rights not conveyed. The issuance of a permit does not convey property rights of any sort, or any exclusive privilege.

(F) Activities not authorized. The issuance of a permit does not authorize any injury to persons or property or invasion of other private rights, or any infringement of State or local law or regulations.

(G) Coordination with exploration. The permittee of a geologic storage well shall coordinate with any operator planning to drill through the AOR to explore for oil and gas or geothermal resources and take all reasonable steps necessary to minimize any adverse impact on the operator's ability to drill for and produce oil and gas or geothermal resources from above or below the geologic storage facility.

(H) Duty to provide information. The operator shall furnish to the Commission, within a time specified by the Commission, any information that the Commission may request to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit, or to determine compliance with the permit. The operator shall also furnish to the Commission, upon request, copies of records required to be kept under the conditions of the permit.

(I) Inspection and entry. The operator shall allow any member or employee of the Commission, on proper identification, to:

(i) enter upon the premises where a regulated activity is conducted or where records are kept under the conditions of the permit;

(ii) have access to and copy, during reasonable working hours, any records required to be kept under the conditions of the permit;

(iii) inspect any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under the permit; and

(iv) sample or monitor any substance or parameter for the purpose of assuring compliance with the permit or as otherwise authorized by the Texas Water Code, §27.071, or the Texas Natural Resources Code, §91.1012.

(J) Schedule of compliance: The permit <u>shall</u> [~~may~~], when appropriate, specify a schedule of compliance leading to compliance with all provisions of this subchapter and Chapter 3 of this title. <u>If the time necessary for completion of any interim requirement is more than one year and is not readily divisible into stages for completion, the permit shall specify interim dates for the submission of reports of progress toward completion of the interim requirements and indicate a projected completion date.</u>

(i) Any schedule of compliance shall require compliance as soon as possible, and in no case later than three years after the effective date of the permit.

(ii) If the schedule of compliance is for a duration of more than one year from the date of permit issuance, then interim requirements and completion dates (not to exceed one year) must be incorporated into the compliance schedule and permit.

(iii) Progress reports must be submitted no later than 30 days following each interim date and the final date of compliance.

(K) Modification, revocation and reissuance, or termination. This permit may be modified, revoked and reissued, or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.

(L) Signatory requirement. All applications, reports, or information shall be signed and certified.

(M) Reporting requirements.

(i) Planned changes. The permittee shall give notice to the director as soon as possible of any planned physical alterations or additions to the permitted facility.

(ii) Anticipated noncompliance. The permittee shall give advance notice to the director of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.

(iii) Transfers. This permit is not transferable to any person except after notice to and approval by the director. The director may require modification or revocation and reissuance of the permit to change the name of the permittee and incorporate such other requirements as may be necessary under the SDWA.

(iv) Monitoring reports. Monitoring results shall be reported at the intervals specified elsewhere in this permit.

(v) Compliance schedules. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit shall be submitted no later than 30 days following each schedule date.

(vi) Twenty-four hour reporting. The permittee shall report any noncompliance which may endanger health or the environment. Any information shall be provided orally to the director within 24 hours from the time the permittee becomes aware of the circumstances. A written submission shall also be provided to the director within five days of the time the permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause, the period of noncompliance, including exact dates and times, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent reoccurrence of the noncompliance. The permittee shall report any noncompliance which may endanger health or the environment including:

(I) any monitoring or other information which indicates that any contaminant may cause an endangerment to a USDW; and

(II) any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between USDWs.

(N) Other information. Where the permittee becomes aware that it failed to submit any relevant facts in a permit application, or submitted incorrect information in a permit application or in any report to the director, it shall promptly submit such facts or information.

(O) Other noncompliance. The permittee shall report all instances of noncompliance not reported under subsection (e) of this section, subparagraphs (J) and (M) of this paragraph, and §5.207(a)(2)(A) of this title at the time monitoring reports are submitted. Any information shall be provided orally to the director within 24 hours from the time the permittee becomes aware of the circumstances. A written submission shall also be provided to the director within five days of the time the permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause, the period of noncompliance, including exact dates and times, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent reoccurrence of the noncompliance. The reports required by this subparagraph shall contain the following information:

(i) any monitoring or other information which indicates that any contaminant may cause an endangerment to a USDW; and

(ii) any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between USDWs.

(P) Incorporation of requirements in permits. New permits, and to the extent allowed under §5.202 of this title modified or revoked and reissued permits, shall incorporate each of the applicable requirements referenced in this section. An applicable requirement is a State statutory or regulatory requirement that takes effect prior to final administrative disposition of the permit. An applicable requirement is also any requirement that takes effect prior to the modification or revocation and reissuance of a permit, to the extent allowed in §5.202 of this title.

(Q) Compliance with SWDA and related regulations. In addition to conditions required in all permits, the director shall establish conditions in permits as required on a case-by-case basis to provide for and assure compliance with all applicable requirements of the SWDA and 40 CFR Parts 144, 145, 146 and 124.

§5.207. Reporting and Record-Keeping.

(a) Reporting requirements. The operator of a geologic storage facility must provide, at a minimum, the following reports to the director and retain the following information:

(1) Test records. The operator must file a complete record of all tests in duplicate with the district office within 30 days after the testing. In conducting and evaluating the tests enumerated in this subchapter or others to be allowed by the director, the operator and the director must apply methods and

standards generally accepted in the industry. When the operator reports the results of mechanical integrity tests to the director, the operator must include a description of any tests and methods used. In making this evaluation, the director must review monitoring and other test data submitted since the previous evaluation.

(2) Operating reports. The operator also must include summary cumulative tables of the information required by the reports listed in this paragraph.

(A) Report within 24 hours. The operator must report the items listed in clauses (i) through (v) of this subparagraph to the director and the appropriate district office orally as soon as practicable, but within 24 hours of discovery, and in writing within five working days of discovery. The written submission shall contain a description of the noncompliance and its cause, the period of noncompliance, including exact dates and times, and if the noncompliance has not been corrected, the anticipated time it is expected to continue, and steps taken or planned to reduce, eliminate, and prevent reoccurrence of the noncompliance. The operator shall report the following items:

(i) the discovery of any significant pressure changes or other monitoring data that indicate the presence of leaks in the well or the lack of confinement of the injected gases to the geologic storage reservoir;[~~. Such report must be made orally as soon as practicable, but within 24 hours, following the discovery of the leak, and must be confirmed in writing within five working days~~]

(ii) any evidence that the injected CO_2 stream or associated pressure front may cause an endangerment to a USDW;

(iii) any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs;

(iv) any triggering of a shut-off system (i.e., down-hole or at the surface); and

(v) any failure to maintain mechanical integrity.

(B) Report within 30 days. The operator must report:

(i) the results of periodic tests for mechanical integrity;

(ii) the results of any other test of the injection well conducted by the operator if required by the director; and

(iii) a description of any well workover.

(C) Semi-annual report. The operator must report:

(i) a summary of well head pressure monitoring;

(ii) changes to the source as well as the physical, chemical, and other relevant characteristics of the CO_2 stream from the proposed operating data;

(iii) monthly average, maximum and minimum values for injection pressure, flow rate, temperature, and volume and/or mass, and annular pressure;

(iv) monthly annulus fluid volume added;

(v) a description of any event that significantly exceeds operating parameters for annulus pressure or injection pressure as specified in the permit;

(vi) a description of any event that triggers a shutdown device and the response taken; and

(vii) the results of monitoring prescribed under §5.206(e) of this title (relating to Permit Standards).

(D) Annual reports. The operator must submit an annual report detailing:

(i) corrective action performed;

(ii) new wells installed and the type, location, number, and information required in §5.203(e) of this title (relating to Application Requirements);

(iii) re-calculated AOR unless the operator submits a statement signed by an appropriate company official confirming that monitoring and operational data supports the current delineation of the AOR on file with the Commission;

(iv) the updated area for which the operator has a good faith claim to the necessary and sufficient property rights to operate the geologic storage facility;

(v) tons of CO_2 injected; and

(vi) other information as required by the permit.

(E) [~~(vi)~~] Annual updates. The operator must maintain and update required plans in accordance with the provisions of this subchapter.

(i) [~~(I)~~] Operators must submit an annual statement, signed by an appropriate company official, confirming that the operator has:

(I) [~~(-a-)~~] reviewed the monitoring and operational data that are relevant to a decision on whether to reevaluate the AOR and the monitoring and operational data that are relevant to a decision on whether to update an approved plan required by §5.203 or §5.206 of this title; and

(II) [~~(-b-)~~] determined whether any updates were warranted by material change in the monitoring and operational data or in the evaluation of the monitoring and operational data by the operator.

(ii) [~~(II)~~] Operators must submit either the updated plan or a summary of the modifications for each plan for which an update the operator determined to be warranted pursuant to subclause (I) of this clause. The director may require submission of copies of any updated plans and/or additional information regarding whether or not updates of any particular plans are warranted.

[~~(vii) other information as required by the permit.~~]

(3) The director may require the revision of any required plan following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the director or

whenever the director determines that such a revision is necessary to comply with the requirements of this subchapter.

(b) Report format.

(1) The operator must report the results of injection pressure and injection rate monitoring of each injection well on Form H-10, Annual Disposal/Injection Well Monitoring Report, and the results of internal mechanical integrity testing on Form H-5, Disposal/Injection Well Pressure Test Report. Operators must submit other reports in a format acceptable to the Commission. At the discretion of the director, other formats may be accepted.

(2) The operator must submit all required reports, submittals, and notifications under this subchapter to the director and to the **EPA** [~~Environmental Protection Agency~~] in an electronic format approved by the director **and the Regional Administrator, respectively**.

(c) Signatories to reports.

(1) Reports. All reports required by permits and other information requested by the director, shall be signed by a person described in §5.203(a)(1)(B) of this title, or by a duly authorized representative of that person. A person is a duly authorized representative only if:

(A) the authorization is made in writing by a person described in §5.203(a)(1)(B) of this title;

(B) the authorization specifies either an individual or a position having responsibility for the overall operation of the regulated facility or activity, such as the position of plant manager, operator of a well or a well field, superintendent, or position of equivalent responsibility; and

(C) the written authorization is submitted to the director.

(2) Changes to authorization. If an authorization under paragraph (1) of this subsection is no longer accurate because a different individual or position has responsibility for the overall operation of the facility, a new authorization satisfying the requirements of paragraph (1) of this subsection must be submitted to the director prior to or together with any reports, information, or applications to be signed by an authorized representative.

(d) Certification. All reports required by permits and other information requested by the director under this subchapter, shall be certified as follows: "I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations."

(e) Record retention.

(1) The operator must retain all data collected under §5.203 of this title for Class VI permit applications throughout the life of the geologic sequestration project and for 10 years following storage facility closure.

(2) The operator must retain data on the nature and composition of all injected fluids collected pursuant to §5.203(j)(2)(A) of this title until 10 years after storage facility closure. The operator shall submit the records to the director at the conclusion of the retention period, and the records must thereafter be retained at the Austin headquarters of the Commission.

(3) The operator must retain all testing and monitoring data collected pursuant to the plans required under §5.203(j) of this title, including wellhead pressure records, metering records, and integrity test results, and modeling inputs and data used to support AOR calculations for at least 10 years after the data is collected.

(4) The operator must retain well plugging reports, post-injection storage facility care data, including data and information used to develop the demonstration of the alternative post-injection storage facility care timeframe, and the closure report collected pursuant to the requirements of §5.206(k)(6) and (m) of this title for 10 years following storage facility closure.

(5) The operator must retain all documentation of good faith claim to necessary and sufficient property rights to operate the geologic storage facility until the director issues the final certificate of closure in accordance with §5.206(k)(7) of this title.

(6) The director has authority to require the operator to retain any records required in this subchapter for longer than 10 years after storage facility closure.

(7) The director may require the operator to submit the records to the director at the conclusion of the retention period.

This agency hereby certifies that the rules as adopted have been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

Issued in Austin, Texas, on August 22nd, 2023.

Filed with the Office of the Secretary of State on August 22nd, 2023.

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