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ASSESSING THE LIABILITY ASSOCIATED WITH GEOLOGIC CARBON SEQUESTRATION: ANALYZING TEXAS OIL & GAS LAW RELATED TO EOR OPERATIONS, WASTE DISPOSAL AND NATURAL GAS STORAGE

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I. Introduction.

Legislation to reduce carbon emissions is inevitable. As carbon-capture technology continues to improve, geologic sequestration of carbon dioxide ("CO_2") is likely to become the primary tool for managing the huge quantities of CO_2 generated by the global industrial economy. Understanding the nature of both the short-term and long-term liability associated with carbon sequestration is a key consideration in developing a sequestration project—especially a project initiated early during the transition from a carbon-intensive economy to a carbon-managed economy.

Texas is likely to be at the forefront of geologic sequestration for a number of structural reasons including: (1) the Texas oil and gas industry's long history of and existing expertise injecting CO_2 for enhanced oil recovery ("EOR") purposes, thus providing a ready market and an economic incentive for carbon capture by industrial generators of CO_2; (2) the numerous depleted oil and gas reservoirs located in Texas that can be used for permanent CO_2 sequestration; (3) the numerous deep saline aquifers, especially along the Gulf Coast, that are considered attractive potential reservoirs for future CO_2 sequestration because of their large storage capacity and relatively few well-bore penetrations which limit the number of available pathways for CO_2 migration; (4) the existence of some physical infrastructure for transporting CO_2 (*i.e.* existing CO_2 pipelines and natural gas lines that can be converted to CO_2 transportation); (5) an existing regulatory framework governing CO_2 injection, albeit one that will likely require additional refinement for purposes of regulating some of the unique aspects of CO_2 sequestration; (6) the recent enactment of tax incentives for EOR projects that rely on anthropogenic (or man-made) sources of CO_2 located in Texas; and (7) a relatively industry friendly legal system. In fact, the operators of two proposed coal-fired power plants recently announced plans to capture some portion of their CO_2 emissions and sell the captured CO_2 to oil and gas operators for use in EOR operations.[3]

Importantly, Texas has a body of statutory and common law that offers valuable insight into the potential liability associated with carbon sequestration. In particular, the Texas oil and gas industry's experience with EOR operations, salt water (or formation water) disposal, hydrogen sulfide (or "sour gas") operations and natural gas storage provides considerable insight into the issue of fluid migration—a major source of potential liability for any geologic sequestration project. This experience gives us a better understanding of the risks associated with geologic sequestration, especially during the operational phase of CO_2 injection operations.

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[3] Tenaska, Inc. has filed a prevention of significant deterioration ("PSD") air quality permit application with the TCEQ for a 600 megawatt (MW) coal-fired power plant that it proposes to construct in Nolan County near Sweetwater, Texas. Tenaska proposes to capture "up to 90% of the CO_2 that would otherwise enter the atmosphere" and transport it to the Permian Basin for EOR operations. Press Release: "Tenaska Proposes Nation's First New Conventional Coal-fueled Power Plant to Capture Carbon Dioxide" (February 19, 2008).

II. The Risks Associated With Geologic Carbon Sequestration.

For purposes of this paper, the discussion regarding the risks and potential legal liabilities associated with geologic carbon sequestration is divided into two phases: (1) the operational phase; and (2) the long-term, post-closure phase. The operational phase is the period during which actual CO_2 injection operations are conducted and the period immediately following well plugging and site closure. The post-closure phase is the period following cessation of injection operations and following the immediate, post-closure period during which the storer is still conducting operations on site. Some risks, like the risk of CO_2 migration, are common to both the operational and post-closure phases of a sequestration project.

Fortunately, there is an existing regulatory framework and body of common law that can be applied today to the operational phase—albeit one that is imperfect in the context of CO_2 sequestration. See section III.A below. It is less clear what existing law would apply to the post-closure phase of storage operations, though there are statutory analogs that offer elements worth analyzing in the context of long-term CO_2 sequestration. Unless CO_2 injection and sequestration operations are specifically exempted, the Resource Conservation and Recovery Act ("RCRA") would likely apply to geologic sequestration operations if (a) the stored CO_2 is deemed a "hazardous" waste by virtue of the presence of constituents that are also "hazardous waste,"[4] and (b) the CO_2 does not fall within the "petroleum exemption" for wastes associated with oil and gas exploration and development.[5] Likewise, if sequestered CO_2 meets the definition of a "hazardous substance," then an escape of that CO_2 from a closed storage facility, for example, might give rise to liability under the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA").[6] While this paper touches on the regulatory and common law potentially applicable to post-closure liability (see sections II.B and III below), other presentations at this conference more directly address long-term, post-closure liability. This paper, therefore, focuses primarily on the risks and liabilities associated with the operational phase.

A. Risks Encountered During the Operational Phase.

The risks associated with the operational phase can be largely managed through good geological site characterization and good operational and well-plugging practices.

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[4] For definition of "hazardous waste," see 40 C.F.R. § 261.3 (2008).

[5] 42 U.S.C. §§ 6901-6992 (West 2008); *see also* Regulatory Determination for Oil and Gas Geothermal Exploration, Development and Production Wastes, 53 Fed. Reg. 25,446 (July 6, 1988).

[6] CERLCA authorizes the federal government (namely EPA) and the states to identify potentially responsible parties ("PRPs") and attribute strict, joint and several liability to current and past owners and operators of facilities where there have been releases of "hazardous substances." Generators and transporters of hazardous substances can also be held liable under CERCLA. Following a CERCLA-type model for assigning responsibility for releases from a CO_2 sequestration site would undoubtedly deter development of a nascent geologic sequestration industry. As a result, a CERCLA-type approach to addressing the potential liability associated with long-term geologic carbon sequestration should be rejected. 42 U.S.C.A. §§ 9601, 9607 (West 2008).

Understanding the risks associated with the operational phase is also crucial to managing operational liability.

(1) Fluid Migration.

Fluid migration is the principal source of potential liability associated with CO_2 injection and sequestration. It is both an operational and post-closure concern. The risks associated with CO_2 migration include: (a) groundwater contamination; (b) damage to property rights by lateral or vertical migration; (c) creation of pressurized zones; (d) migration that results in gaseous CO_2 accumulations potentially harmful to humans; and (e) migration that results in leakage of CO_2 to the atmosphere.

To understand the risks associated with CO_2 sequestration, it is important to be familiar with certain physical characteristics of CO_2. At normal or atmospheric temperatures and pressures, CO_2 is a gas. CO_2 injected for EOR or sequestration purposes is first compressed to a supercritical state at which point the CO_2 takes on characteristics of both a liquid and a gas.[7] Carbon dioxide achieves a supercritical state at temperatures above 31.1 degrees Celsius (88 degrees Fahrenheit) and pressures above 73.8 bar (or 1,072 psi).[8] Supercritical CO_2 is less viscous (*i.e.* has a higher mobility) than either water or oil and will tend to be more buoyant than water or oil and tend to migrate upwards.[9] Thus, a good geologic trapping mechanism is important to ensure long-term sequestration.[10] CO_2 can also be physically trapped within formation pore space by capillary forces (essentially, the forces of adhesion).[11] At depths below 2,500 feet, CO_2 behaves as a liquid.[12] At shallower depths, liquid CO_2 can change phase and become a gas.[13] So CO_2 injected as a liquid can change phase as it migrates towards the surface.

Migration of injected CO_2 can occur along either geologic pathways (such as faults) or along mechanical or man-made pathways (such as abandoned or improperly plugged wells). Limiting liability due to migration along geologic pathways is best achieved through good geologic site characterization. Limiting liability associated with mechanical pathways is best achieved by selecting project areas with few potential pathways or by choosing to inject into deep geologic formations, which naturally have fewer well-bore penetrations. Thus, analyzing the geologic characteristics of the storage formation, existing well-bore penetrations and potential risk receptors can limit the liability associated with fluid migration. In some instances, operational changes such as reducing injection pressure or volumes can eliminate or reduce fluid migration along either man-made or geologic pathways.[14]

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[7] Intergovernmental Panel on Climate Change, *IPCC Special Report on Carbon Dioxide Capture and Storage* 385-386 (Cambridge University Press, New York, 2005) ("2005 IPCC Report").
[8] *Id.*
[9] *Id.* at 205-206.
[10] *Id.* at 31–33.
[11] *Id.*
[12] *Id.* at 197.
[13] *Id.*
[14] *Id.* at 253.

(a) Groundwater Contamination.

Carbon dioxide in water is, generally speaking, not harmful (think carbonated water). However, migrating CO_2 can be a vehicle for transporting heavy metals or brackish water that can contaminate freshwater aquifers. Migrating CO_2 can also displace underground brackish water by pushing or banking it into aquifers, thereby degrading fresh water. Groundwater supplies almost 60% of all the water used in Texas.[15] In the last several years, development of large scale groundwater projects has increased the economic value of the state's groundwater resources. Again, good geologic site characterization and monitoring during the operational and post-closure phases of project development is a key to limiting liability exposure for damage to surrounding groundwater resources. In addition, compliance with the groundwater protection rules is essential. See discussion below regarding the Underground Injection Control ("UIC") program.

(b) Damage to Property Rights.

Migrating CO_2 can also cross property lines and encroach upon neighboring surface or mineral estates, thereby leading to possible trespass, nuisance and negligence claims. Encroachment upon the mineral estate (especially when injecting for EOR purposes) can also lead to statutory oil and gas waste claims.[16] In the context of carbon sequestration, a waste claim would most likely arise if CO_2 forced salt water into an oil and gas reservoir, thus rendering some or all of the hydrocarbons unrecoverable. Parties seeking to sequester CO_2 into formations formerly productive of oil or gas should also consider the likely existence of residual hydrocarbon accumulations and the possible need to acquire both the surface and mineral estates when selecting the location of a future sequestration project. Case law analyzing the liability associated with impacts to surrounding property rights is discussed in section III.B. below.

(c) Pressurized Zones.

Migrating CO_2 can also pressurize subsurface formations. Drilling through pressurized formations can cause blowouts potentially resulting in property damage or personal injury. Encountering pressure-charged water zones during drilling operations is fairly common in the oil and gas industry. While pressurized zones most commonly occur as a result of natural mechanisms, some charged zones are the result of injected fluids escaping from the zone of injection and subsequently accumulating in another formation.

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[15] Texas Water Development Board, *2007 State Water Plan* 176 (2007).

[16] Oil and gas "waste" is defined in part as "the drowning with water a stratum or part of a stratum that is capable of producing oil or gas or both in paying quantities." *See* TEX. NAT. RES. CODE ANN. § 85.046(a)(2) (Vernon 2001); *see also* TEX. NAT. RES. CODE ANN. § 85.321 (Vernon 2001) (authorizing private cause of action for violation of waste-prevention provisions).

(d) Accumulations Harmful to Humans.[17]

Excluding the cumulative effects of global warming, CO_2 migration poses relatively low risk to human health. Localized accumulations of gaseous CO_2, however, can be harmful to humans. Carbon dioxide is 1.5 times denser than air and can thus displace air in low lying or poorly ventilated areas like basements.[18] The risk to humans is dependent on the concentration of CO_2 and the length of exposure to harmful concentrations. At concentrations as low as 2 to 3%, CO_2 can cause ill health effects such as headaches, labored breathing, visual impairment and disorientation.[19] Death can result at concentrations as low as 7 to 10% depending on length of exposure.[20] The risk to humans is compounded by the fact that CO_2 is colorless and generally odorless.[21] An increased level of monitoring for sequestration projects developed in densely populated areas may be warranted and should be evaluated by the project developer and the regulating authority.

(e) Leakage to the Atmosphere.

CO_2 migration that results in leakage to the atmosphere defeats the purpose of CO_2 sequestration in the first place and could result in liability for remediation of the facility to prevent future releases (*e.g.* reentering and replugging abandoned wells identified as potential pathways), removal of the CO_2 for reinjection into a different formation, enforcement actions by the regulating agency or mass tort liability. It is likely that legislation governing CO_2 sequestration will require a demonstration that the CO_2 will be geologically sequestered for a period of at least 1,000 years. For instance, in 2007 the 80th Texas Legislature enacted a severance-tax exemption for oil and gas operators that utilize anthropogenic CO_2 for EOR and that can demonstrate that 99% of the CO_2 will be sequestered for at least 1,000 years.[22]

(2) Other Operational Risks.

Other potential areas of operational risk include pipeline leaks, surface damage due to surface releases of chemicals or drilling fluids, poor casing or cementing of injection wells, fracturing the injection formation due to poor pressure management and the risk of injury to workers. Also, the need to reenter and replug existing but abandoned well bores that could act as potential pathways is especially likely in sequestration projects that propose to inject CO_2 into former oil and gas fields. As discussed below, Texas case law discussing the rights or obligations of parties to reenter plugged oil and gas wells is surprisingly poorly developed. See section III.B.(6) below.

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[17] For a brief but excellent discussion of the potential harmful effects of CO_2 accumulations, *see* Rogers, Aaron, *The Common Law Liability Potential of Carbon Dioxide Storage, Sequestration and Enhanced Recovery* (June 2006).
[18] 2005 IPCC Report, *supra* note 5, at 390.
[19] *Id.* at 391.
[20] *Id.*
[21] *Id.* at 385.
[22] TEX. TAX CODE ANN. § 202.0545 (Vernon Supp. 2007) (entitled "Tax Exemption for Enhanced Recovery Projects Using Anthropogenic Carbon Dioxide"); 16 TAC §3.50 (West 2008) (entitled "Enhanced Oil Recovery Projects—Approval and Certification for Tax Incentive").

(3) Induced Seismic Activity and Limnic Eruptions.

There have been reported cases of injection operations causing dramatic increases in formation pressure to the extent that they actually induce seismic activity.[23] Even in the few reported instances of alleged induced seismic activity, however, there was scant scientific evidence establishing a causal link between the injection operations and the seismic activity.[24]

Also, two events of catastrophic releases of CO_2 accumulations from lakes were documented in 1986 at Lake Nyos and 1984 at Lake Monoun in Cameroon, Africa. These natural disasters, called limnic eruptions, resulted when the lakebeds became super-saturated with CO_2. The lakebeds then suddenly erupted, releasing huge volumes of CO_2 that displaced the surrounding air. The CO_2 asphyxiated the unsuspecting inhabitants living near the lakes, tragically resulting in more than 1700 deaths.[25]

Both induced seismic activity and limnic eruptions are extremely rare and the risk is minimal for purposes of developing a liability risk profile.

B. Post-Closure Liability.

The need to stabilize and ultimately reduce atmospheric concentrations of CO_2 is now widely acknowledged. However, the need to sequester carbon indefinitely presents a unique set of risks. The risks associated with long-term sequestration must be understood and addressed through legislation before wide-spread deployment of commercial CO_2 sequestration is likely to occur. While many of the risks associated with the operational phase of carbon sequestration are also present post closure (*e.g.* the risks associated with fluid migration), a carbon-sequestration-project developer is faced with considerable uncertainty due to the current lack of a regulatory framework for the post-closure phase of carbon sequestration operations. Insurance products for managing the long-term liability associated with these risks are being developed. Until legislation is enacted defining the scope of this liability, however, this uncertainty is a deterrent to the development of sequestration projects.

Given the global nature of atmospheric warming and the widespread benefits that geologic sequestration projects would provide, the private sector should not and cannot realistically be forced to bear the entire liability associated with 1,000+ year sequestration projects. Undoubtedly, commercial sequestration operations will emerge and prosper. It is equally clear that operators of commercial-sequestration facilities and their customers (primarily industrial generators of CO_2) should assume some of the cost of post-closure monitoring and, if necessary, post-closure remediation of a compromised or leaking storage project. However, because long-term maintenance and monitoring of a storage site will be necessary to ensure

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[23] Rogers, *supra* note 15, at 4-5.
[24] *Id.*
[25] *See* Zhang Youxue, *Dynamics of CO2-driven lake eruptions*. Nature 379, 57-59 (July 4, 1996).

permanent sequestration and because corporations have finite lives, it is highly likely that government will assume some measure of responsibility for post-closure site stewardship.[26]

Last year, Congress considered numerous pieces of legislation that address global climate change including provisions for the long-term liability associated with closed storage sites. The bill garnering the most attention was the Lieberman-Warner Climate Security Act of 2008 ("Lieberman-Warner").[27] If enacted, Lieberman-Warner would have amended the Safe Drinking Water Act ("SDWA")[28] to include sweeping legislation to control greenhouse gas emissions. Title VIII of the bill set forth a "Framework for Geologic Sequestration of Carbon Dioxide" which would have required the Environmental Protection Agency ("EPA") to promulgate regulations for permitting underground CO_2 injection including provisions "relating to long-term liability associated with commercial-scale geological sequestration."[29] The bill defined "geologic sequestration" as the "permanent isolation of greenhouse gases without reversal, in geologic formations, in accordance with Part C of the SDWA (42 U.S.C. 300h *et seq.*) as determined by the Administrator" of EPA.[30] The bill further directed EPA to establish a task force to study the feasibility of "potential Federal assumption of liability with respect to closed geologic storage sites."[31] Though it offers insight as to how the U.S. Congress might address long-term liability, this bill never became law as it was not passed during the session of the 110th Congress.

In contrast to the Lieberman-Warner federal approach to carbon regulation, the Interstate Oil and Gas Compact Commission ("IOGCC") proposes that the states are better equipped to provide the long-term oversight–particularly post-closure–necessary to effectively regulate carbon sequestration projects. In 2002, the IOGCC convened a "Task Force on Carbon Capture and Geologic Storage" charged with generating a guidance document to assist states with developing regulations relating to carbon sequestration. In 2007, the Task Force unveiled its *Model Statute and General Rules and Regulations for Geologic Storage of Carbon Dioxide*, which covers everything from permitting to post-closure liability.[32]

With respect to permitting, the Task Force strongly asserts that an amalgamation of property rights is critical to the orderly development of a CO_2 storage project. Thus, the model statute and regulations require an operator to obtain all necessary property interests in the geological storage unit–utilizing eminent domain or unitization proceedings as necessary–before a permit is issued.[33]

To deal with long-term monitoring and liability issues, the Task Force proposes a ten-year closure period in which the operator would maintain a performance bond sufficient to cover

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26 Wilson, Elizabeth J. and De Figueiredo, Mark A., *Liability and Financial Responsibility for Carbon Capture and Sequestration* 4 (Word Resources Institute, December 2007).
27 *See* S. 3036, 110th Cong. (2008) ("Lieberman-Warner").
28 42 U.S.C.A. 300f-300j (West 2008); *see* discussion of SDWA *infra* section III.A.(1).
29 Lieberman-Warner at § 8001(d)(1)(B).
30 *Id.* at § 4(13).
31 *Id.* at § 8001.
32 *See* Interstate Oil and Gas Compact Commission, *Storage of Carbon Dioxide in Geologic Structures, A Legal and Regulatory Guide for States and Provinces*, (September 25, 2007).
33 *See id.* at App. I (Model Statute), § 3; *see also* App. II (Model Rules and Regs), § 4.1(a)(1).

plugging and abandonment or remediation of injection wells.[34] At the end of the closure period the operator's performance bond is released, and responsibility for monitoring and remediation of the storage site including any associated liability transfers to the state.[35] Section 6 of the Model Statute establishes a state-administered "Carbon Dioxide Storage Facility Trust Fund" to cover any post-closure site-related costs. Funding is achieved through an injection fee or tax on storage operators for each ton of carbon injected for storage.[36]

The cost of long-term monitoring and maintenance programs will undoubtedly be significant. Thus, establishing a funding mechanism to ensure the availability of the necessary resources to pay for post-closure maintenance and monitoring is key to assessing long-term liability.

III. Assessing the Liability Associated With Geologic Carbon Sequestration by Analyzing Texas Statutory and Common Law Governing the Oil & Gas Industry.

Cases involving migration of injected fluids—the most likely source of liability associated with carbon sequestration—generally involve elements of administrative law, property law and tort law. In fact, all of the leading cases discussing fluid migration or subsurface trespass involve legal issues within these distinct areas of the law. Another common thread in these cases is a discussion of the "public interest." Thus, to fully analyze the potential liability associated with geologic sequestration, it is important to understand how these areas of the law interact with each other and how the "public interest" factors into the case law.

In order to develop a sequestration project, the project developer must acquire or obtain the necessary rights to inject CO_2 into the pore space of a subsurface geologic formation. In Texas, however, it is not clear whether the pore space is owned by the surface or mineral estate. Therefore, the acquisition of the requisite property interests requires an understanding of the relationship between the surface and mineral estates, a relationship that factors prominently in the relevant case law. Clearly, a sequestration-project developer that acquires both the surface and minerals of a sufficiently large tract (in terms of both acreage and the thickness of the proposed injection interval) takes an important step towards limiting its liability. Of course, regardless of tract size, the injection interval must have available pore space, good reservoir characteristics, and good reservoir integrity (*i.e.* a good trapping mechanism and minimal avenues for migration) in order to be a suitable site for sequestration.

Upon acquisition of a suitable tract and completion of the necessary engineering and geologic evaluation, the next step in the development process will be the filing of an injection application with the relevant state agency. Under current regulations governing injection of CO_2 for EOR purposes, injection of formation water or injection of other wastes, the applicant must

[34] *Id.* at App. II, § 4.1.
[35] *Id.* at App. II, § 9(j).
[36] *Id.* at App. I.

provide notice of its application and an opportunity for a hearing to affected persons.[37] This notice and hearing process is an element of potential liability that is often overlooked.

The regulatory process can be a source of risk for a number of reasons. First, the regulating agency could deny the permit application, which might result in the loss of certain sunk costs, such as the costs associated with the engineering, geologic and legal evaluation of the property, the cost of property acquisition, and the cost of filing and prosecuting the permit application. Second, even assuming the regulatory agency is inclined to recommend approval of the permit application, an affected party could lodge a protest, resulting in a contested-case proceeding, which could then lead to denial of the permit application. Further, if the administrative law judge recommends approval of the permit application after conducting a contested-case proceeding and the agency adopts that determination, the protesting party still has the right to appeal that decision. Finally, even if the applicant prevails at both the hearing and appellate stages, a contested-case proceeding provides the protesting party with the opportunity to acquire evidence, information, or favorable findings of fact or conclusions of law that might be useful in formulating a suit for damages or injunctive relief. On the other hand, the regulating authority's granting of a permit and the permit-holder's compliance with the terms of that permit can be a significant benefit to the permit holder involved in litigation regarding the permitted operations. This has been especially true in Texas in suits alleging subsurface trespass due to injection operations.

A. Texas Regulation of EOR, Salt Water Disposal, Natural Gas Storage Operations and Sour Gas Operations.

Because they are operationally similar, EOR, salt-water disposal, acid-gas disposal (from processing sour gas) and natural-gas-storage operations provide a useful model for evaluating the potential liability associated with geologic carbon sequestration. For the most part, the regulations governing injection of CO2 for EOR operations (*i.e.* injection to maximize recovery of oil), injection of natural gas for gas-storage purposes (*i.e.* injection for storage of a commodity) and the injection of sour gas or salt water (*i.e.* injection for disposal purposes) are very similar. But there has been considerable debate regarding whether it is more appropriate to treat anthropogenic CO_2 as a waste or a resource. From the perspective of injection operations governed under the UIC program, the distinction between resource and waste is largely irrelevant. The more important distinction is whether the CO_2 contains impurities rendering it a hazardous waste (regulated under RCRA). Under current UIC regulations, if the composition of the injected fluid (or "injectate") renders the injectate hazardous, then the injectate must be injected under the more stringent Class 1 industrial-well rules applicable to hazardous wastes. In July 2008, EPA proposed new rules governing injection wells used for carbon sequestration.[38] The preamble to these proposed rules suggests that EPA will continue to require the owner or operator of a proposed well to determine whether the injectate is hazardous as part of the well-permitting process.[39] Regardless of the purpose for injecting CO_2 and regardless of whether it is

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[37] *See, e.g.*, 16 TAC §§ 3.9(5), 3.46(c) (West 2008) (notice provisions of wells under Railroad Commission of Texas jurisdiction).

[38] 73 Fed. Reg. 43491-43541 (July 2008).

[39] *Id.* at 43503.

characterized as a waste or a resource, the primary function of the UIC is to protect usable groundwater.

(1) Underground Injection Control (UIC) Program.

The UIC program provides an existing regulatory framework for the operational phase of CO_2 injection operations. The UIC program was created under the SDWA, which authorizes EPA to adopt rules and administer the UIC.[40] The purpose of the UIC program, whether administered at the federal or state level, is to protect "underground sources of drinking water" from contamination by regulating the construction, operation and testing of injection wells.[41] The term "underground sources of drinking water" is defined as an aquifer or portion of an aquifer that: (1) supplies any public water system or contains a quantity of groundwater sufficient to supply a public water system; (2) currently supplies drinking water for human consumption; or (3) contains fewer than 10,000 mg/L total dissolved solids ("TDS") and is not an exempt aquifer.[42]

States can assume primacy over administration of the UIC program by submitting their UIC program to EPA for approval.[43] In Texas, the authority to administer the UIC has been delegated to the Railroad Commission ("RRC") and Texas Commission on Environmental Quality ("TCEQ").[44] Chapter 27 of the Texas Water Code sets out the agencies' respective authority. The UIC program creates five classes of wells (Classes I through V). The RRC regulates Class II wells that dispose of "oil and gas wastes" including salt water or formation water associated with oil and gas production, fluids (including CO_2) injected as part of EOR operations and hydrocarbons injected for storage.[45] Water Code section 27.036 also authorizes the RRC to regulate brine mining wells, which are classified as Class III wells.[46] In addition,

[40] *See* 42 U.S.C.A. 300f-300j (West 2008).

[41] Texas Water Code § 27.003 (entitled "Policy and Purpose") provides: "It is the policy of the state and the purpose of this chapter to maintain the quality of fresh water in the state to the extent consistent with the public health and welfare of the operation of existing industries, taking into consideration the economic development of the state, to prevent underground injection that may pollute fresh water, and to require the use of all reasonable methods to implement this policy." TEX. WATER CODE ANN. § 27.003 (Vernon Supp. 2007).

[42] 40 C.F.R. § 144.3 (2008). The term "aquifer" is defined under EPA rules as "a geological formation, group of formations, or part of a formation that is capable of yielding a significant amount of water to a well or spring." *Id.*

[43] 42 U.S.C.A. §§ 300h—300h-8.

[44] 40 C.F.R. § 147.2251 (2008) (for Texas' Class II program); 40 C.F.R. § 147.2200 (2008) (for Texas' Class I, III, IV and V programs).

[45] TEX. WATER CODE ANN. § 27.002 (Vernon Supp. 2008). The following fluids can be injected into a Class II well: produced water from oil and gas production; waste fluids from the actual drilling operations; pigging fluids from the cleaning of gathering and injection lines within the field; used workover and stimulation fluids recovered from production, injection, and exploratory wells; gas, such as methane, CO_2 or nitrogen, used for enhanced recovery/pressure maintenance; brine reject from water softeners associated with enhanced recovery; waste fluids from methane sweetening and dehydration, which is blended with produced water, as long as it is not hazardous at the point of injection; waste sour gas from the methane sweetening process; waste fluids from circulation during well cementing; waste oil and fluids from cleanup associated with primary production (but not the transportation) of oil within the oil field; fresh water used for enhanced recovery makeup; water containing chemicals such as polymers for the purpose of enhanced recovery; and drill cuttings from wells associated with oil and gas production. U.S. EPA, *Technical Program Overview: Underground Injection Control Regulations*, App. D, 63-64 (Dec. 2002).

[46] TEX. WATER CODE ANN. § 27.036 (Vernon 2000).

Water Code section 27.038 states: "The railroad commission has jurisdiction over injection of carbon dioxide produced by a clean coal project, to the extent authorized by federal law, into a reservoir that is productive of oil, gas, or geothermal resources by a Class II injection well, or by a Class I injection well if required by federal law."[47] TCEQ regulates all other injection wells including all other Class I injection wells.[48]

Owners and operators of Class I injection wells that inject hazardous waste must also comply with EPA's "no-migration standard" developed under RCRA. Under the strict no-migration standard, an owner or operator of a well that injects hazardous waste must demonstrate that the well will not negatively impact the environment for 10,000 years.[49] Wastes generated during the exploration, drilling, development and production of oil and gas (including EOR operations) are exempt from regulation under RCRA and, therefore, are exempt from the no-migration rule.[50] The policy underpinnings for exempting the oil and gas industry from RCRA (*i.e.* to promote domestic oil and gas production by limiting the regulatory costs associated with waste handling and disposal) could easily be used to justify exempting injection for geologic sequestration purposes from RCRA regulation. Clearly, exempting CO_2 injection operations from RCRA would remove a potential barrier to developing sequestration projects in the immediate future.[51] However, such an exemption requires legislative action and, until that occurs, EPA's proposed rules make it clear that the current practice of evaluating the composition of the injectate to determine whether it is hazardous will determine the specific UIC rules applicable to CO_2 injected for carbon sequestration.

TCEQ and RRC UIC rules both provide for notice of an injection-well permit application and an opportunity for hearing.[52] Affected persons can protest an application and request an evidentiary hearing. RRC rules define "affected person" as "a person who has suffered or will suffer actual injury or economic damage other than as a member of the general public or as a competitor, and includes surface owners of property on which the well is located and commission-designated operators of wells located within one-half mile of the proposed disposal well."[53] TCEQ rules define "affected person" as "any person whose legal rights, duties, or privileges may be adversely affected by the proposed injection operation for which a permit is sought."[54]

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[47] *See* TEX. WATER CODE ANN. § 27.038 (Vernon Supp. 2007) (entitled "Jurisdiction Over Carbon Dioxide Injection").

[48] 16 TAC § 3.30(d)(2) (West 2008) (entitled "Memorandum of Understanding between the Railroad Commission of Texas (RRC) and the Texas Commission on Environmental Quality (TCEQ)").

[49] *See* Moore, Jeffrey W., *The Potential Law of On-Shore Geologic Sequestration of* CO_2 *Captured from Coal-Fired Power Plants,* 28 Energy L. J., 443, 460 (2007); *see also Natural Res. Defense Council v. EPA,* 907 F.2d 1146, 1157 (D.C. Cir. 1990) (recognizing EPA's authority to apply RCRA to hazardous-waste injection).

[50] Regulatory Determination for Oil and Gas Geothermal Exploration, Development and Production Wastes, 53 Fed. Reg. 25,446 (July 6, 1988).

[51] CO_2 generated at coal-fired power plants and other sources can have hazardous constituents depending on the fuel being burned and the emissions control technologies employed.

[52] *See* 16 TAC §§ 3.9(5), 3.46(c) (West 2008); *see also* 30 TAC §§331.1 *et. seq.* (West 2008).

[53] *See* 16 TAC § 3.46(c)(5)(B) (West 2008) (for injection into a reservoir productive of oil or gas); *see also* 16 TAC § 3.9(5)(E)(ii) (West 2008) (for injection into a disposal well).

[54] 30 TAC § 331.2(3) (West 2008) (entitled "Definitions").

Water Code §27.051 (entitled "Issuance of Permit") states the grounds upon which the TCEQ and RRC may respectively grant an injection permit:

(a) The commission may grant an application in whole or in part and may issue the permit if it finds:
   (1) that the use or installation of the injection well is in the public interest;
   (2) that no existing rights, including, but not limited to, mineral rights, will be impaired;
   (3) that, with proper safeguards, both ground and surface fresh water can be adequately protected from pollution;
   (4) that the applicant has made a satisfactory showing of financial responsibility if required by Section 27.073 of this code;
   (5) that the applicant has provided for the proper operation of the proposed hazardous waste injection well;
   (6) that the applicant for a hazardous waste injection well not located in an area of industrial land use has made a reasonable effort to ensure that the burden, if any, imposed by the proposed hazardous waste injection well on local law enforcement, emergency medical or fire-fighting personnel, or public roadways, will be reasonably minimized or mitigated; and
   (7) that the applicant owns or has made a good faith claim to, or has the consent of the owner to utilize, or has an option to acquire, or has the authority to acquire through eminent domain, the property or portions of the property where the hazardous waste injection well will be constructed.

(b) The railroad commission may grant an application in whole or in part and may issue the permit if it finds:
   (1) that the use or installation of the injection well is in the public interest;
   (2) that the use or installation of the injection well will not endanger or injure any oil, gas, or other mineral formation;
   (3) that, with proper safeguards, both ground and surface fresh water can be adequately protected from pollution; and
   (4) that the applicant has made a satisfactory showing of financial responsibility if required by Section 27.073 of this code.[55]

Both sets of rules provide for protection of fresh water, the prevention of mineral waste, a showing of financial responsibility and that proposed injection is "in the public interest."[56] With the exception of establishing financial responsibility, these factors all figure prominently in the case law involving injection and fluid migration discussed below.

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[55] TEX. WATER CODE ANN. § 27.051 (Vernon Supp. 2007) (emphasis added).

[56] *See Texas Citizens for a Safe Future & Clean Water v. Railroad Comm'n of Texas*, 2007 WL 4269869 (Tex. App.-Austin 2008, no pet.) (recent case remanding appeal of a RRC order granting injection permit for consideration of additional factors that may affect the "public interest" but recognizing that the Legislature did not specify what factors should be considered).

UIC rules also provide for mechanical integrity testing of the injection well and regular reporting of injection pressures, injection rates and cumulative injected volumes.[57] The frequency of testing and reporting is dependent on the well's classification under the UIC.[58] From a purely environmental-protection viewpoint, one arguable deficiency in the current UIC regulatory framework is the lack of any express requirement for ensuring that the injected fluids are contained in the injection zone (with the exception being the no-migration standard for hazardous wastes). Rather, the focus of the rules and agency implementation of the rules is primarily on injection-well integrity with less emphasis placed on geologic characterization and virtually no requirement for post-injection monitoring.[59]

Waste-injection cases interpreting Texas Water Code section 27.051 offer some guidance regarding the liability associated with CO_2 sequestration. In *FPL Farming, Ltd. v. Texas Nat. Res. Conservation Comm'n*, a neighboring surface estate owner sought to overturn issuance of a wastewater-injection-well permit issued by TCEQ where the evidence showed that the proposed injection of liquid waste into a salt water bearing formation was likely to cross onto FPL's property.[60] The plaintiffs, FPL Farming, alleged that TCEQ had violated Texas Water Code section 27.051 by improperly focusing on FPL's lack of intended and foreseeable uses of the deep-injection zone rather than on FPL's existing property rights in that zone.[61] At the hearing, FPL presented testimony that it might produce saltwater in the future or use the injection interval for its own wastewater disposal operation. Holding that issuance of the permits did not impair FPL's existing rights, the Austin Court of Appeals found that FPL was free to apply for a permit to use the formation for the identified potential future uses and that FPL must show the migration caused "some measure of harm" to an existing use in order for "impairment" to arise under section 27.051(a)(2).[62] It is worth noting, however, that the *FPL Farming* case was an appeal of an administrative order granting a permit application. Citing Texas Water Code section 27.104, the court expressly noted that FPL could pursue civil damages if migration of the waste plume caused harm.[63]

Liability may also arise in the form of civil or criminal penalties. If a permit holder violates the terms of its permit or otherwise violates the Water Code Chapter 27, or the rules of the regulating agency (*i.e.* TCEQ or RRC depending on the well classification), then the regulating agency can file suit seeking injunctive relief "or other appropriate remedy" or assess civil or administrative penalties following the procedures set out in Chapter 27, subchapter F (entitled "Civil and Criminal Remedies").[64] A person that "knowingly or intentionally" violates

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[57] U.S. EPA, *Technical Program Overview: Underground Injection Control Regulations*, Table 1, p. 11 (December 2002).
[58] *Id.*
[59] Moore, *supra* note 46, at 462-63.
[60] *FPL Farming, Ltd. v. Tex. Nat. Res. Conservation Comm'n*, 2003 WL 247183 (Tex. App.–Austin 2003) (mem. op., not designated for publication).
[61] *Id.* at 3.
[62] *Id.* at 4.
[63] *Id.* at 5.
[64] TEX. WATER CODE ANN. §§ 27.101-27.105 (Vernon 2000).

a provision of Chapter 27, an agency rule or the terms or conditions of an injection permit may be subject to criminal fines.[65]

(a) EPA's Proposed Rules Regulating Injection for Carbon Sequestration.

In July 2008, EPA published proposed rules that would govern the injection of CO2 for sequestration purposes.[66] EPA proposes a new class of wells for geologic sequestration of CO2—Class VI wells. The proposed rules would create standards for the siting, construction, operation, monitoring, testing and closure of Class VI wells. Because these proposed rules are subject to further revision, the details of the proposed rules are not discussed here. However, under its proposed rules, EPA may require among other things: extensive geologic and geochemical site characterization; identification and analysis of any existing well that penetrates the area of review and corrective action by the sequestration project operator of any well to "address deficiencies" regardless of well ownership; sophisticated, multi-phase modeling that recognizes the supercritical characteristics of injected CO_2; well construction techniques that recognize the buoyancy of CO_2 including requirements for horizontal injection wells; use of corrosion-resistant materials; monitoring and tracking of the CO_2 plume; and development of a post-injection site care and site closure plan that provides for monitoring for up to 50 years following cessation of injection.[67] Also, EPA is proposing a requirement that the owner or operator demonstrate acceptable financial responsibility but offers little in the way of specifics on this point other than to state that additional guidance will be forthcoming.[68]

(2) <u>Natural Gas Storage.</u>

The statutes and rules governing natural gas storage also provide guidance to regulators developing rules for carbon sequestration as well as guidance to the developers of sequestration projects. Like the UIC, hydrocarbon storage rules place significant emphasis on water protection, prevention of oil and gas waste, and public policy considerations. Texas Natural Resources Code section 91.202 states:

> **§ 91.202. Policy**
>
> It is the policy of this state and the purpose of this subchapter to prevent the waste of oil, gas, and products of oil or gas, to protect the ground and surface water of the state from unreasonable degradation, and to protect the public health, welfare, and physical property in the creation, operation, maintenance, and abandonment of underground hydrocarbon storage facilities.[69]

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[65] *Id.*
[66] 73 Fed. Reg. 43491-43541 (July 2008).
[67] *Id.*
[68] *Id.* at 43520.
[69] TEX. NAT. RES. CODE ANN. § 91.202 (Vernon 2001).

Chapter 91 confers eminent domain authority on operators of natural gas storage facilities.[70] Section 91.180(a) states: "The finding by the commission that underground storage is in the public interest is binding on all persons whose property the storer has the right to condemn. After that finding of the commission, the storer has the right to condemn all of the underground storage area and any surface area required for the use and enjoyment of the storage facility."[71] This right to condemn includes the right to condemn minerals and royalty interests "reasonably necessary for the operation of the storage facility."[72] The right to condemn (either surface or minerals) is subject to the following limitations:

> (1) no part of a reservoir is subject to condemnation unless the storer has acquired by option, lease, conveyance, or other negotiated means at least 66-2/3 percent of the ownership of minerals, including working interests, and a 66-2/3 percent of the ownership of the royalty interests, computed in relation to the surface area overlying the part of the reservoir which is found by the commission to be expected to be penetrated by displaced or injected gas;
> (2) no dwelling, barn, store, or other building is subject to condemnation; and
> (3) the right of condemnation is without prejudice to the rights of the owners or holders of other rights or interests of land to drill through the storage facility under such terms and conditions as the commission may prescribe for the purpose of protecting the storage facility against pollution or escape of natural gas and is without prejudice to the rights of the owners or holders of other rights or interests of the land to all other uses so long as those uses do not interfere with the operation of the storage facility.[73]

Once a permit is issued, the storer may condemn any remaining interests necessary to complete the storage project by initiating eminent domain proceedings under section 91.180.

In the event of condemnation, section 91.182 makes clear that the stored gas is the personal property of the gas storer, thus alleviating any concerns regarding ownership between the surface estate and the mineral estate—an approach that makes sense in a carbon sequestration context.[74] The Legislature, however, clearly distinguishes native gas from stored gas–implying that native gas remains part of the mineral estate. The Legislature gave the storer the right to seek injunctive relief in the event any party other than the storer or the storer's assigns attempts to take possession of the stored gas. Section 91.182 states:

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[70] TEX. NAT. RES. CODE ANN. § 91.180 (Vernon 2001).
[71] *Id.*
[72] TEX. NAT. RES. CODE ANN. § 91.179 (Vernon 2001).
[73] *Id.*
[74] *See* TEX. NAT. RES. CODE ANN. § 91.182 (Vernon 2001); *see also Lone Star Gas Co. v. Murchison*, 353 S.W.2d 870, 879-880 (Tex. Civ. App.—Dallas 1962, writ ref'd n.r.e) (holding that stored natural gas had become personal property and title to that property was not lost when that gas migrated onto neighboring property).

§ 91.182. **Ownership of Stored Gas**

> All natural gas in the stratum condemned which is not native gas, and which is subsequently injected into storage facilities is personal property and is the property of the injector or its assigns, and in no event is the gas subject to the right of the owner of the surface of the land or of any mineral or royalty owner's interest under which the storage facilities lie, or of any person other than the injector to produce, take, reduce to possession, either by means of the law of capture or otherwise, waste, or otherwise interfere with or exercise any control over a storage facility. Upon failure, neglect, or refusal of the person to comply with this section, the storer has the right to compel compliance by injunction or by other appropriate relief by application to a court of competent jurisdiction.[75]

Clearly, legislation conferring condemnation authority, which allows the sequestration project developer the ability to acquire all necessary ownership rights including the right to acquire necessary pipeline and surface facilities, would be beneficial to an emerging CO_2 sequestration industry.[76] Absent condemnation authority, the proposed storage of CO_2 in a formation formerly productive of oil or gas will require the storer to somehow account for residual native hydrocarbons. Otherwise, a confusion of goods dispute is likely to ensue.

(3) <u>H_2S Regulations</u>.

Carbon dioxide often contains impurities such as hydrogen sulfide (or "sour gas"). Sour gas can be harmful to humans at concentrations as low as 100 ppm.[77] Injection facilities or pipelines containing CO_2 with H_2S concentrations in excess of 100 ppm and otherwise falling within RRC jurisdiction are subject to RRC Rules 36 and 106. RRC Rule 106 (entitled "Sour Gas Pipeline Facility Construction Permit") states that no person may commence construction of a "sour gas pipeline facility" without first obtaining a permit.[78] A sour gas pipeline is any

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[75] TEX. NAT. RES. CODE ANN. § 91.182 (Vernon 2001).

[76] Section 91.184 (entitled "Abandonment") provides that upon permanent abandonment of a storage facility the storer shall file a Notice of Abandonment with the RRC and a notice in the deed records that all condemned property shall "revert to those who owned the property at the time of condemnation, or their heirs, successors, or assigns." TEX. NAT. RES. CODE ANN. § 91.184 (Vernon 2001). Arguably, a reversion to the prior owners has no place in the context of carbon sequestration where CO_2 storage is intended to be permanent. One possible exception might be if there is unused pore space.

[77] Railroad Commission of Texas, Statewide Rule 36 Hydrogen Sulfide Safety Manual, pp. 4-6 (May 2005).

[78] 16 TAC § 3.106 (West 2008) ("Sour Gas Pipeline Facility Construction Permit"). Exceptions to the permit requirement include:

(1) an extension of an existing sour gas pipeline facility that at the time of construction of the extension is in compliance with §3.36 of this title (relating to oil, gas, or geothermal resource operation in a hydrogen sulfide area) if:
  - (A) the extension is not longer than five miles;
  - (B) the nominal pipe size is not larger than six inches; and
  - (C) the operator causes to be delivered to the Safety Division written notice of construction of the extension not later than 24 hours before the start of construction;

(2) a new gathering system that operates at a working pressure of less than 50 pounds per square inch gauge;

pipeline facility that contains 100 ppm or more of H_2S. Rule 106 provides for notice and an opportunity for an evidentiary hearing for affected persons (*i.e.* persons owning or occupying real property within the 100 ppm radius of influence).[79] Likewise, RRC Rule 36 (entitled "Oil, Gas, or Geothermal Resource Operations in Hydrogen Sulfide Areas") requires operators conducting operations involving H_2S with concentrations of 100 ppm or more (including injection and associated surface facilities) to comply with the various safety, reporting and other requirements provided in the rule.[80] Therefore, pipeline, gas processing or EOR operations involving CO_2 with H_2S concentrations of 100 ppm or more would clearly have to comply with Rules 36 and/or 106 unless otherwise exempt under those rules.

B. Texas Common Law.

In general, Texas common law, especially case law discussing pore space ownership, subsurface trespass, and injection operations, should be viewed favorably by would-be developers of carbon sequestration projects. But to fully weigh the liabilities associated with carbon sequestration in Texas, the common law must be examined.

(1) Ownership of the Pore Space.[81]

In Texas, a conveyance or reservation of minerals creates two estates.[82] The mineral estate is dominant to the surface estate, and the mineral owner has the right to use the surface to the extent necessary and reasonable to develop and remove the minerals.[83] However, Texas law is unsettled as to which real property estate, the surface or the mineral, owns the subsurface pore space. While Texas case law provides valuable guidance regarding pore space ownership, parties seeking to engage in CO_2 sequestration would be well advised to select locations where they can acquire both the surface and minerals.

Gas-storage cases, in particular, offer insight on the issue of pore-space ownership in Texas. In *Humble Oil & Ref. Co. v. West*, owners of reserved royalty interests brought suit to enjoin use of a gas field for gas storage purposes until such time as all the native gas to which they were entitled to royalty was produced.[84] Humble (the party seeking to store gas) owned

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(3) an extension of a gathering system which operates at a working pressure of less than 50 pounds per square inch gauge;
(4) an interstate gas pipeline facility, as defined by 49 U.S.C. § 60101, that is used for the transportation of sour gas; or
(5) replacement of all or part of a sour gas pipeline facility if the area of influence of the replaced portion of the facility does not increase so as to include a public area, as defined in §3.36(b)(5) of this title, not included in the area of influence of the portion of the replaced sour gas pipeline facility. *Id.*

[79] 16 TAC § 3.106 (West 2008)(entitled "Sour Gas Pipeline Facility Construction Permit.")

[80] 16 TAC § 3.36 (West 2008) (entitled "Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas").

[81] For an excellent in-depth discussion of pore-space ownership, see Anderson, Owen, *Geologic Carbon Sequestration: Who Owns the Pore Space?* (2008 Carbon and Climate Change Conference, University of Texas at Austin).

[82] *Humphreys-Mexia Co. v. Gammon*, 254 S.W. 296, 299 (Tex. 1923).

[83] *Sun Oil Co. v. Whitaker*, 483 S.W.2d 808, 810 (1972); *Getty Oil Co. v. Jones*, 470 S.W.2d 618, 621 (Tex. 1971); *Humble Oil & Refining Co. v. Williams*, 420 S.W.2d 133, 134 (Tex. 1967).

[84] *Humble Oil & Ref. Co. v. West,* 508 S.W.2d 812 (Tex. 1974).

both the surface and mineral estates in fee simple. The court noted that Humble, as the owner of the surface estate, owned "the matrix of the underlying earth" subject only to the reserved royalty interests.[85] Much of the opinion, however, is focused on a "confusion-of-goods" analysis. While the court held that the gas storer retained ownership of the injected gas as personal property, the gas storer had the burden to allocate between native gas and injected gas.[86] In arriving at its decision, as in other cases involving gas storage or EOR operations, the court weighed the public interest and spoke of the need to balance "the interests of society and the interests of the oil and gas industry as a whole against the interest of the individual operator."[87] In the context of carbon sequestration, *West* is primarily instructive in the context of its *dicta* regarding pore-space ownership. The *West* opinion might also be instructive in a confusion-of-goods situation where injected anthropogenic CO_2 is mixed with residual CO_2 from prior injection operations.

The *West* court's conclusion that the surface estate owns the "matrix of the underlying earth" relied heavily on the decision in *Emeny v. United States*.[88] In *Emeny*, the United States Court of Claims was confronted with the question of whether the right to store gas in the Bush Dome in Potter County, Texas, belonged to the mineral lessee or the surface owners.[89] The original 1923 oil and gas leases allowed the lessee to "produce, save and take care of" the oil and gas production which included some native helium. The federal government subsequently acquired the mineral leases with the intent to store non-native helium or helium produced "off lease."[90] The *Emeny* court, citing the express terms of the original leases, held that "the surface of the leased lands and everything in such lands, except the oil and gas deposits covered by the leases, were still the property of the respective landowners."[91] This ownership interest included the "geological structures beneath the surface, including any structure that might be suitable for underground storage of 'foreign' or 'extraneous' gas produced elsewhere."[92]

While *Emeny* and *West* stand for the proposition that the surface estate owns the subsurface pore space, a contrary result was reached in the *MAPCO* case. In *MAPCO v. Carter*, the Court found that the mineral estate owner rather than the surface owner retained ownership of the storage capacity in an underground salt dome that had been created by salt leaching operations.[93] Ignoring *Emeny* and *West* and suggesting that the law regarding pore-space ownership was "well-recognized," the *MAPCO* Court reasoned that, because the mineral owner owned the salt (a mineral) that comprised the walls of the cavern, then the mineral owner naturally owned the storage space.[94]

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[85] *Id.* at 815.
[86] *Id.* at 818-819.
[87] *Id.* at 816.
[88] *Emeny v. United States*, 412 F.2d 1319, 188 Ct. Cl. 1024 (1969).
[89] *Id.* at 1321.
[90] *Id.* at 1322.
[91] *Id.* at 1323.
[92] *Id.*
[93] *MAPCO, Inc. v. Carter*, 808 S.W.2d 262, 274 (Tex. Civ. App.—Beaumont 1991), *rev'd in part on other grounds*, 817 S.W.2d 686 (Tex. 1991).
[94] *Id.* at 276-278.

Despite the *MAPCO* court's assertions to the contrary, the ownership of subsurface pore space is not well-settled in Texas. On balance, the surface estate appears to have the better claim to pore-space ownership.[95] Other jurisdictions appear to agree.[96] However, the surface estate's claim to the pore space is not unfettered. For instance, the surface estate's ownership of a depleted oil and gas formation is clearly subject to the mineral estate's right to any remaining or residual minerals.[97] While no formation yields 100% of its oil and gas reserves, technological improvements continually raise the ultimate recovery of oil and gas formations. This is important especially if one considers that injection operations for sequestration purposes might permanently render residual minerals unrecoverable. Reasonable estimations of the remaining hydrocarbons in place are possible and would allow a carbon sequesterer the ability to purchase residual hydrocarbons if necessary. Of course, a better approach would be to acquire both the surface and mineral estates where possible and thus avoid the entire confusion-of-goods issue.

(a) Salt Water Injection Operations and the Mineral Estate's Reasonable Use of the Surface.

Texas common law permits mineral lessees to dispose of saltwater produced on-lease by injecting into subsurface formations without the consent of the surface owner. When a mineral lessee acquires an oil and gas lease, those rights include, either expressly or impliedly, the right to use as much of the surface as is reasonably necessary to produce and develop the minerals.[98] Texas Courts have determined that the on-lease disposal of saltwater produced by on-lease oil and gas operations is a reasonable use of the surface estate. A lessee, therefore, has the right to dispose of saltwater produced in conjunction with mineral development and the mineral lessee may dispose of this produced water by injecting it into subsurface formations that are part of the surface estate.[99] However, absent authority from the surface estate owner (*e.g.* via contract), the disposal of saltwater produced off the lease is deemed an unreasonable use of the land.[100]

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[95] The Williams and Meyers Oil and Gas Law Treatise supports a contrary position. It urges adoption of the position that a severance of the mineral estate should be construed as granting the exclusive rights to subterranean strata for all purposes relating to minerals, whether "native" or "injected," absent contrary language in the instrument severing such minerals. 1 Williams & Meyers: Oil & Gas Law § 222 (2007).

[96] The U.S. Department of the Interior Board of Land Appeals found that "the general rule in the United States appears to be that, once the minerals have been removed from the soil, the space occupied by the minerals reverts to the surface owner by operation of law. This rule stems from the general interpretation of a mineral grant as giving the grantee the right to explore for, produce, and reduce to possession if found, the minerals granted, but not the stratum of rock containing the minerals." *See Mallon Oil Co.*, 104 I.B.L.A. 145, 150 (1988) (appeal from a decision by the Miles City, Montana, District Office, Bureau of Land Management); *see also International Salt Co. v. Geostow*, 697 F.Supp. 1258 (W.D.N.Y. 1988).

[97] Nelson, Thomas K., *Ownership of Depleted Underground Formations: A Hypothetical Supreme Court Opinion*, 10 Texas Oil and Gas L. J. 29 (June 1996).

[98] *See Sun Oil Co. v. Whitaker*, 483 S.W.2d 808, 810 (1972); *Getty Oil Co. v. Jones*, 470 S.W.2d 618, 621 (Tex. 1971); *Humble Oil & Refining Co. v. Williams*, 420 S.W.2d 133, 134 (Tex. 1967).

[99] *D.B. Stephens v. Finley Resources, Inc.*, 2006 WL 768877 (Tex.App. – Amarillo 2006, no pet.) citing *TDC Engineering, Inc. v. Dunlap*, 686 S.W.2d 346, 348-49 (Tex.App. – Eastland 1985, writ ref'd n.r.e.); *Brown v. Lundell*, 344 S.W.2d 863, 869 (Tex. 1961).

[100] *See Application of Global Oil Corp. to Inject Fluid into a Reservoir Productive of Oil or Gas, Ramsey 122 Lease Well No. 2, Powell Field, Navarro County, Texas,* O&G Docket No. 05-0245884 (May 8, 2006) (finding that an oil and gas lessee is limited to on-lease disposal operations unless a separate agreement is obtained from the surface owner that allows the oil and gas operator to conduct commercial disposal operations); *see also Application of J.L. McGill for Saltwater Disposal in the Benedum (Spraberry) Field, Upton County, Texas,* O&G Docket No. 7C-

From the perspective of a carbon-sequestration-project developer, this case law is potentially problematic because it creates the possibility of competing uses for the right to inject into saline formations. Particularly troublesome is that the surface estate is servient to the mineral estate and that competing uses could compromise storage integrity. The danger here is that a mineral lessee might inject into the same formation as a person seeking to inject supercritical CO_2 and, thus, create both competition for the available pore space and potential pathways for CO_2 migration (*e.g.* an improperly cemented or cased salt water injection well). These issues emphasize that, to the extent practicable, the developer of a carbon-sequestration project is well served to acquire both the surface and mineral estates and, thereby, avoid both competing uses of the target-injection zone and the creation of possible mechanical pathways for CO_2 leakage. This conflict, however, might first arise in the context of the administrative proceedings initiated by either a mineral lessee or storage developer seeking approval of an application to inject. In fact, a pre-existing use of a formation by either of the two competing uses could preclude the other from subsequent use of the injection formation, unless the applicant can establish that the projects are compatible and will not result in the escape of either injected substance.

(2) Trespass.

The potential for injected CO_2 to migrate onto neighboring lands is an obvious source of potential liability. In the context of subsurface trespass, Texas courts have analyzed two fact scenarios closely related to injection for sequestration purposes: (a) the migration of fluids injected as part of EOR or secondary (*i.e.* waterflooding) operations; and (b) well stimulation operations that create fractures that cross property lines.

The leading case addressing the potential for subsurface trespass caused by secondary injection operations is *Railroad Comm'n of Texas v. Manziel.*[101] In *Manziel*, the plaintiff was an oil and gas operator that sought to set aside an injection permit that the RRC had issued to an offsetting operator and to enjoin injection operations conducted pursuant to that permit. The plaintiff alleged that water injected pursuant to the permit would cross onto plaintiff's property and damage plaintiff's producing wells. The question before the Texas Supreme Court was whether the plaintiffs could enjoin duly authorized injection operations to prevent a subsurface trespass. Reversing the trial court's issuance of an injunction, the Court held that when "the Commission authorizes a secondary recovery project, a trespass does not occur when the injected, secondary recovery ***forces*** move across lease lines."[102] The Court elaborated by quoting the well known oil and gas treatise *Williams & Meyers* stating:

76,475 (April 14, 1981) (citing *Eubank v. Twin Mountain Oil Corp.*, 406 S.W.2d 789, 792 (Tex.Civ.App.–Eastland 1966, writ ref'd n.r.e.) (finding that while a surface owner is free to apply for a permit to inject into formations that are part of the surface estate, that surface owner is limited in its ability to use abandoned oil and gas wells for disposal operations).

[101] *See Railroad Comm'n of Texas v. Manziel*, 361 S.W.2d 560 (Tex. 1962).

[102] *Id.* at 568 (emphasis added).

> What may be called a 'negative rule of capture' appears to be developing. Just as under the rule of capture a land owner may capture oil or gas as will migrate from adjoining premises to a well bottomed on his own land, so also may he inject into a formation substances which may migrate through the structure to the land of others, even if this results in displacement under such land of more valuable with less valuable substances . . .[103]

In arriving at its decision, the Court relied heavily on the public interest benefits of secondary recovery operations stating:

> It is obvious that secondary recovery programs could not and would not be conducted if any adjoining operator could stop the project on the grounds of subsurface trespass. As is pointed out by *amicus curiae*, if the Manziels' theory of subsurface trespass be accepted, the injection of salt water in the East Texas field has caused subsurface trespasses of the greatest magnitude.
>
> The orthodox rules and principles applied by the courts as regards surface invasions of land may not be appropriately applied to subsurface invasions as arise out of the secondary recovery of natural resources. If the intrusions of salt water are to be regarded as trespassory in character, then under common notions of surface invasions, the justifying public policy considerations behind secondary recovery operations could not be reached in considering the validity and reasonableness of such operations.[104]

Manziel, like other fluid-migration cases, involves a legal analysis that draws upon principles of property, administrative and tort law with much of the justification for the Court's opinion resting on public-policy grounds. Like the *FPL Farming* case discussed above, *Manziel* is not a case about damages. As the Court notes, it did not address whether the "Commission's authorization of such operations throws a protective cloak around the injecting operator who might otherwise be subjected to the risks of liability for actual damages to the adjoining property."[105]

The Court's reference to secondary recovery "forces" rather than secondary recovery "water" suggests that the Court may have recognized that the potential trespass plaintiff sought to enjoin may not have been an actual physical invasion of injected water but rather an invasion of pressure influences that banked water towards plaintiff's producing wells. This recognition by the *Manziel* Court is potentially significant in the context of CO_2 sequestration operations where migrating CO_2 could cause the banking of saltwater on adjacent properties. The Court's language suggests that the *Manziel* Court, at least, might find no trespass in such an instance. Regardless, the holding in *Manziel* provides potentially powerful precedent for sequesterers of CO_2 primarily because of its refusal to allow injunctive relief to prevent subsurface trespass and because of its apparent adoption of the "negative rule of capture."

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[103] *Id.* (citing 1 Williams & Meyers: Oil & Gas Law § 204.5 n.1 (2007)).
[104] *Id.* at 568.
[105] *Id.* at 566.

As potentially beneficial to CO_2 sequestration as holdings like *Manziel* and *FPL Farming* might appear, the secondary recovery operations in *Manziel* can be distinguished from CO_2 sequestration in a deep saline aquifer. This is especially true if such operations are ultimately treated as waste disposal by EPA, thus distinguishing them from EOR or secondary recovery operations. Likewise, neither *Manziel* nor *FPL Farming* involved a suit for damages.

In the oil and gas industry, wells are often hydraulically fractured to increase production. In a "frac job," specially formulated frac fluids are pumped into the well at high pressure to fracture a potentially productive formation. The injection of supercritical CO_2 at high pressures and volumes can cause fracturing within the injection zone. In some instances, fracturing is beneficial because it can lead to increased injectivity and storage capacity. However, in other instances, induced fracturing can lead to the escape of injected fluids. Understanding the rock properties of the injection zone including the fracture gradient of the injection zone and confining strata both above and below the injection zone is critical to managing fracture length and avoiding the escape of injected fluids.

Recently, in *Coastal Oil & Gas Corp. v. Garza Energy Trust*, the Texas Supreme Court analyzed whether hydraulic fractures extending onto neighboring property constituted subsurface trespass and whether damages were recoverable for drainage resulting from the frac job.[106] Holding that the rule of capture barred recovery, the *Coastal* Court, like the *Manziel* Court, avoided addressing the issue of whether the subsurface invasion of a neighboring tract (in this case by hydraulic fracturing) constituted a trespass. While recognizing that technological advances make estimation of the length and general direction of a hydraulic fracture possible, the Coastal Court demured stating that "material facts are hidden below miles of rock."[107] And once again we see the Supreme Court rely heavily on public policy in deciding a case involving subsurface operations stating:

> . . . there is an even greater difficulty with litigating recovery for drainage resulting from fracing, and it is that trial judges and juries cannot take into account social policies, industry operations, and the greater good which are tremendously important in deciding whether fracing should or should not be against the law.[108]

Coastal's reliance on public policy is in many ways a continuation of the rationale proffered in *Manziel* and provides significant insight into how Texas courts are likely to analyze allegations of trespass that might arise in the context of CO_2 injected for sequestration purposes. Indeed, one could argue that the public policy benefits of carbon sequestration as a means of addressing global climate change are more obvious and compelling than the benefits associated with hydraulic fracturing of oil and gas wells.

(3) <u>Nuisance.</u>

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[106] *Coastal Oil & Gas Corp. v. Garza Energy Trust*, 268 S.W.3d 1 (Tex. 2008).
[107] *Id.*
[108] *Id.*

Cases involving fluid migration, contamination of groundwater or air emissions are often pled as nuisance suits. A "nuisance" is a condition that substantially interferes with the use and enjoyment of land by causing unreasonable discomfort or annoyance to persons of ordinary sensibilities.[109] "Even if a commercial enterprise holds a valid statutory permit to conduct a particular business, the manner in which it performs the activity may give rise to an action for injunctive relief or damages."[110]

The limitations period for a private nuisance claim is two years.[111] The date upon which the cause of action accrues depends on whether the nuisance alleged is permanent or temporary.[112] A permanent nuisance claim accrues when injury first occurs or is discovered.[113] A temporary nuisance claim accrues anew upon each injury.[114] A temporary nuisance is one that is limited in duration, intermittent, "sporadic and contingent upon some irregular force such as rain."[115] A "permanent" nuisance is one that is "constant and continuous."[116] Temporary and permanent injuries are mutually exclusive and a plaintiff may recover for only one of them in any single action.[117]

Cases of temporary nuisance may be brought for damages incurred in the previous two years, regardless of when the first injury occurred or was noted. Cases of permanent nuisance must be brought within two years of first discovery, or they are barred *forever.*[118] Further, suits for damages for past and future injury should be estimated in one suit.[119] A temporary nuisance may be abated by an injunction. A permanent nuisance cannot be enjoined.[120] Another important element of a nuisance claim is the measure of damages which is discussed in further detail below.

(4) <u>Negligence.</u>

Suits alleging damage as a result of fluid migration are often brought as negligence actions. In order to establish negligence, a plaintiff must prove: (1) the defendant owed the plaintiff a specific duty; (2) the defendant breached that duty; (3) the breach is the proximate cause of plaintiff's injury; and (4) the plaintiff suffered damages as a result of the breach.[121]

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[109] *Schneider Nat. Carriers, Inc. v. Bates*, 147 S.W.3d 264, 269 (Tex. 2004).
[110] *Manchester Terminal Corporation v. Texas Marine Transportation, Inc.*, 781 S.W.2d 646, 650 (Tex.App.–Houston [1st Dist.] 1989, writ denied).
[111] TEX. CIV. PRAC. & REM. CODE ANN. §16.003 (Vernon 2002).
[112] *Schneider*, 147 SW.2d at 270.
[113] *Bayouth v. Lion Oil*, 671 S.W.2d 867, 868 (Tex. 1984).
[114] *Schneider*, 147 S.W.3d at 270.
[115] *Bayouth*, 671 S.W.2d at 868.
[116] *Schneider*, 147 S.W.3d at 272; *Bayouth*, 671 S.W.2d at 868.
[117] *Kraft v. Langford*, 565 S.W.2d 223, 227 (Tex. 1978).
[118] *Bayouth*, 671 S.W.2d at 878 (Tex. 1984).
[119] *Atlas Chemical Industries, Inc. v. Anderson*, 524 S.W.2d 681, 684-685 (Tex. 1975) (suit alleging contamination of groundwater due to operation of saltwater pits by oil companies).
[120] *Kraft*, 565 S.W.2d at 227; *Restatement (Second) of Torts* §930(2) (1979).
[121] *Anthony v. Chevron USA, Inc.*, 284 F.3d 578, 583 (5th Cir. 2002, reh'g denied).

Establishing causation in fluid-migration cases has repeatedly proved difficult. Perhaps the best example of the difficulty Texas plaintiffs have establishing causation in a fluid migration context is the case of *Anthony v. Chevron.*[122] In this case, surface estate owners brought suit alleging negligent pollution of the freshwater Allurosa aquifer located beneath their ranch. In the mid-1970s, before the alleged contamination, chloride levels initially tested at 60 ppm and total dissolved solids ("TDS") tested at 600 ppm, both well below the recommended maximum concentration levels ("MCLs") for potable water which are 300 ppm for chlorides and 1,000 ppm for TDS.[123] In 1971, Chevron converted several producing oil wells to saltwater injection in order to increase production.[124] Subsequently, in 1988, fresh water samples taken from plaintiff's Bentley water well tested at levels well above the MCLs for TDS and chlorides.[125]

In an attempt to establish causation, Plainitff's expert presented three different scenarios to show how Chevron's injected salt water might have migrated to and contaminated the aquifer. First, plaintiff's expert presented evidence that the injection zone was a closed system and that once Chevron filled that system, additional injection caused the pressure in that zone to increase to a point where fluid was forced out of the injection zone up into the aquifer via existing wellbores.[126] However, the Fifth Circuit upheld the trial court's determination that plaintiff's expert had failed to establish the size of the closed system and further held that plaintiff's expert admitted that gas in the injection zone could compress, adding additional capacity to the injection zone. In other words, plaintiff failed to establish how much water the injection zone was capable of receiving.[127] Second, the plaintiff presented evidence of casing leaks and water migrating up the outside of the casing. However, the trial court held that the plaintiff failed to show that the salt water had in fact migrated all the way to the aquifer.[128] Finally, the plaintiff presented evidence that two of Chevron's wells had been hydraulically fractured and caused the creation of vertical fractures emanating from the injection zone. Once again, the Fifth Circuit upheld the trial court's ruling that the plaintiff failed to show that the vertical fractures had been propagated up into the aquifer, thus causing contamination.[129] Summarizing the evidence the Court stated:

> Taken as a whole, Epley's [plaintiff's expert] testimony raises suspicions about Chevron's operations in the area. This alone, however, is not enough to present a question of fact to the jury on the issue of causation. Each one of the models presented by Epley provides a plausible theory of how the Bentley Windmill was contaminated. The evidence upon which each of Epley's theories is based, however, is fundamentally lacking. He has not provided any evidence establishing the nexus between Chevron's water injection operations and the pollution in the Allurosa.[130]

[122] *Id.* at 581.
[123] *Id.* at 581-582.
[124] *Id.* at 582.
[125] *Id.*
[126] *Id.* at 584-585.
[127] *Id.* at 585.
[128] *Id.* at 585-586.
[129] *Id.* at 586.
[130] *Id.* at 588.

Anthony v. Chevron demonstrates the difficulty plaintiffs have establishing causation in fluid-migration cases. Fluid-migration cases are by their nature difficult to prosecute because they involve the subsurface and largely unobserved movement of fluid. Other important limiting factors in fluid-migration cases include the running of the limitations period and the measure of damages.[131]

(5) Permanent v. Temporary Damage to Real Property.

The measure of damages for harm to the surface estate due to sequestration operations (for instance, as a result of fluid migration or due to a pipeline release) depends on whether the injury is temporary or permanent in nature. Regardless, the measure of damages in both instances is capped by the market value of the property. This cap is significant when evaluating potential liability associated with carbon sequestration.

The right to sue for injury to real property is a personal right that belongs to the person who owns the property at the time of the alleged injury.[132] Absent an express conveyance, the right to sue does not pass to a subsequent purchaser.[133] As a result, a subsequent purchaser of the property cannot recover for an injury committed before his purchase.[134] In the event of migration from a storage facility that causes property damage, a purchaser of the damaged property might lose the right to sue the storage operator, unless the seller who owned the property at the time the damage occurred properly assigns that right to the purchaser.

The measure of damages for permanent injury to real property is the diminution in the fair market value as measured before and after the injury.[135] The measure of damages for temporary injury to real property is the cost of restoration. However, if the cost of restoration

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[131] Limitations are not discussed in this paper because whether the limitations period has run or has tolled (*e.g.* for fraudulent concealment) generally involves a fact-intensive analysis. One limitations case involving alleged groundwater contamination is worth noting, however, because of its potential relevance to subsurface migration of sequestered CO_2. *See Mitchell Energy Corp. v. Bartlett*, 958 S.W.2d 430 (Tex. App.—Fort Worth 1997, pet. denied). Complaining that their well water tasted bad and smelled like rotten eggs, a number of landowners sued Mitchell, alleging that twelve of Mitchell's natural gas wells had polluted their water. The jury awarded the landowners actual, compensatory and punitive damages on their claims of nuisance, negligence, trespass, violation of administrative rules and fraud. *Id.* at 435.

The Forth Worth court of appeals reversed on limitations grounds, finding improper the jury question that had required a determination whether the landowners had filed their suits within two years of discovering "the *cause in fact of the pollution*." *Id.* at 436 (emphasis original). The court clarified that a plaintiff's cause of action for permanent damage (*i.e.* damage that is "continuous and ongoing") to property "accrues when the plaintiff discovers or should have discovered the *fact* of the injury," as opposed to the cause of the injury. *Id.* (emphasis original). "Thus, the [two-year] statute of limitations began running when appellees discovered that they could not use their water because of its terrible smell and taste." *Id.* at 438. Some of the *Mitchell* landowners had discovered the polluted water fifteen years before filing suit.

[132] *Exxon Corp. v. Pluff*, 94 S.W.3d 22, 27 (Tex.App—Tyler 2002, pet denied).
[133] *Id.*
[134] *Id.*
[135] *Mieth v. Ranchquest*, 177 S.W.3d 296, 303 (Tex.App.-Houston [1st Dist.] 2005, no. pet.).

exceeds the diminution in fair market value, then the proper measure of damages is the diminution in fair market value.[136]

(6) Re-Entering Plugged and Abandoned Wells to Prevent or Halt Fluid Migration.

The existence of wellbores penetrating the storage formation creates the potential for fluid migration through active wells, where corrosion has weakened cement or caused casing leaks, or through abandoned wells that were improperly plugged. Obviously, numerous well penetrations are likely when CO_2 is injected into an oil reservoir for EOR purposes or injected into a depleted oil or gas reservoir for permanent sequestration. Storage facility developers should consider re-entering and re-plugging existing wells that penetrate the storage formation at the outset of a sequestration project as a preventative measure. Further, in the event of fluid migration, a storage facility owner is likely to re-enter abandoned wellbores and re-plug them in order to stop the escape of injected fluids. It is important, therefore, that developers of CO_2 sequestration projects be apprised of Texas law concerning the ownership of, and the right to re-enter, plugged and abandoned oil and gas wells.

As with the law addressing pore-space ownership, the law concerning the ownership and right to use plugged or abandoned wells is not particularly well developed. Under Texas law, a well constitutes an improvement to real property.[137] An improvement to real estate becomes the property of the fee owner.[138] Further, the abandonment of real property is not recognized in Texas and, thus, title to real property interests acquired under an oil and gas lease may not be abandoned.[139]

In *Eubank v. Twin Mountain Oil Corp.*, the court acknowledged that "wells are part of the real estate" and found that "upon the termination of the leases the wells became the property of the lessors."[140] The court further held that the mineral interest owner and its successors in title including subsequent lessees are entitled to control the premises for mineral development including the right to use "abandoned" wells.[141] In *Browning v. Melon*, the San Antonio Court of Appeals likewise held that a mineral lessee had the right to use abandoned wells.[142] The *Browning* court further held that the surface owner was not entitled to interfere with or impede the mineral lessee's right to re-enter previously abandoned wells.[143]

While oil and gas operators may have the right to re-enter previously abandoned wells (including a well plugged by a prior operator), it does not appear that the subsequent operator has the obligation to re-enter an improperly plugged well and re-plug it unless that operator assumes

[136] *Atlas Chemical Industries, Inc. v. Anderson,* 514 S.W.3d 309, 318 (Tex.Civ.App.—Texarkana 1974) *aff'd* 524 S.W.2d 681 (Tex. 1975).
[137] *Francis v. Coastal Oil & Gas Corp.,* 130 S.W.3d 76, 85 (Tex.App.—Houston [1st Dist.] 2003, no pet.); *Foxworth-Galbraith Lumber Co. v. Thorp,* 86 S.W.2d 644, 645 (Tex.Civ.App.—Amarillo 1935, no writ).
[138] *Howle v. Howle,* 422 S.W. 2d 252, 255 (Tex.Civ.App. —Tyler 1967, no writ).
[139] *Rogers v. Ricane,* 772 S.W.2d 76, 80 (Tex. 1989).
[140] *Eubank v. Twin Mountain Oil Corp.,* 406 S.W.2d 789, 792 (Tex.Civ.App. —Eastland 1966, writ ref'd n.r.e.).
[141] *Id.*
[142] *Browning v. Melon Exploration Co.,* 636 S.W.2d 536, 539 (Tex.App. —San Antonio 1982, writ dism'd).
[143] *Id.*

such liability. The nature of this property "right," therefore, is not entirely clear. Texas Natural Resources Code section 89.011 (entitled "Duty to Plug Wells") places the responsibility for plugging an oil and gas well on the well's last Railroad Commission-recognized operator.[144] If the responsible operator fails to plug an abandoned well, then the responsibility falls to the non-operating working interests owners of the well.[145] If both the last operator of record and all working interest owners are unavailable (*e.g.* due to bankruptcy), then the well is listed for plugging by the state using funds from the Oil-Field Cleanup Fund which is financed primarily through fees charged to oil and gas operators.[146] Unplugged or improperly plugged wells that are most likely to endanger human health or fresh water are given highest priority for state-funded plugging.[147]

Clearly, case law holding that the mineral estate has the right but not the obligation to re-enter plugged oil or gas wells makes re-entry of a plugged well problematic for operators of carbon storage facilities that wish to re-enter the well to eliminate it as a potential pathway for CO_2 migration. This situation is alleviated if the project developer acquires both the surface and mineral estates in fee. Alternatively, the project developer should seek an assignment of any existing wellbores or the contractual right to re-enter and permanently re-plug any existing wellbores that pose a threat of migration.

IV. Conclusion.

Texas common law regarding fluid migration, pore-space ownership, and the relationship between the surface and mineral estates, and the existence and continuing evolution of UIC regulations applicable to CO_2 injection operations, provide an adequate legal framework for assessing the liability associated with the operational phase of a geologic sequestration project. Acquiring the necessary ownership interests or rights to use both the surface and mineral estates by the storage project developer and complying with existing (and likely future) UIC regulations are the two most important steps towards limiting liability during the operational phase.

The existing legal framework, however, was not designed to address the technical and legal issues unique to the long-term sequestration of anthropogenic CO_2 as a means of controlling global climate change. As a result, further refinement, especially of the regulatory portion of this legal framework, is necessary to ensure long-term storage integrity through good geologic site characterization, sound operational and site-closure practices, post-closure monitoring, post-closure facility inspection and maintenance, and remediation in the event of leakage. EPA's proposed rules for Class VI injection wells are a significant step towards creating greater clarification in the operational phase of a sequestration project. Until legislation is adopted establishing funding mechanisms for long-term post-closure monitoring, maintenance and remedial operations and addressing long-term responsibility for such operations, the uncertainty associated with long-term liability will be a barrier to widespread commercial

[144] TEX. NAT. RES. CODE ANN. § 89.011 (Vernon Supp. 2006) (entitled "Duty of Operator").
[145] TEX. NAT. RES. CODE ANN. § 89.012 (Vernon 2001) (entitled "Duty of Nonoperator").
[146] TEX. NAT. RES. CODE ANN. §§ 91.111 &112 (Vernon Supp. 2006) (entitled "Oil-Field Cleanup Fund" and "Purposes of the Fund" respectively).
[147] TEX. NAT. RES. CODE ANN. § 91.1132 (Vernon Supp. 2006) (entitled "Prioritization of High-Risk Wells").

deployment of geologic carbon sequestration projects. Two steps that would add significant clarity on the issue of long-term liability and promote development of sequestration projects are: (1) exempting CO_2 injection and sequestration operations from RCRA hazardous-waste regulation upon demonstration of good geologic site characterization and sound operational and site closure practices by the project developer as part of the regulatory approval process (and by applying the same public-policy rationale used to create the RCRA petroleum exemption); and (2) government or public assumption of responsibility for long-term, post-closure monitoring, maintenance and remedial operations of closed carbon storage facilities perhaps funded through an injection fee on storage operators for each ton of carbon injected.