Compendium of Regulatory Requirements Governing Underground Injection of Drilling Wastes

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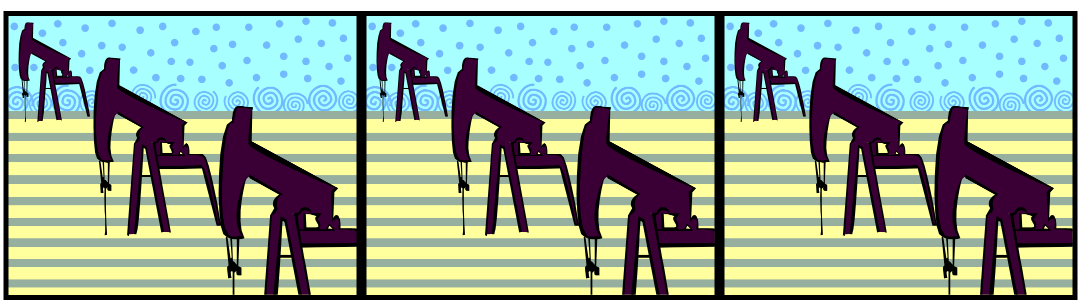

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TABLE OF CONTENTS

ACRONYMS, INITIALISMS, AND ABBREVIATIONS 1

CHAPTER 1 INTRODUCTION 3

PURPOSE OF REPORT 3

FEDERAL LEGAL BACKGROUND 3

TYPES OF INJECTION PROCESSES 4

CHAPTER 2 BARRIERS TO THE USE OF SLURRY INJECTION 6

ECONOMIC BARRIERS 6

REGULATORY BARRIERS 7

CHAPTER 3 OVERVIEW OF INJECTION REQUIREMENTS AND PRACTICES 9

SLURRY INJECTION 9

SUB-FRACTURE INJECTION 9

ANNULAR INJECTION 9

PLUGGING AND ABANDONMENT 11

SALT CAVERN DISPOSAL 11

DISPOSAL IN MINES 11

CHAPTER 4 STATE REQUIREMENTS AND PRACTICES FOR INJECTION OF DRILLING WASTES ... 12

ALABAMA ... 12

ALASKA ... 13

ARIZONA ... 15

ARKANSAS ... 15

CALIFORNIA ... 16

COLORADO ... 17

FLORIDA ... 17

ILLINOIS ... 18

INDIANA ... 18

KANSAS ... 19

KENTUCKY ... 20

LOUISIANA ... 20

MICHIGAN ... 22

MISSISSIPPI ... 22

MISSOURI ... 24

MONTANA ... 24

NEBRASKA ... 25

NEVADA ... 25

NEW MEXICO ... 26

NEW YORK ... 26

NORTH DAKOTA ... 26

Ohio 28

Oklahoma 28

Pennsylvania 30

South Dakota 30

Tennessee 31

Texas 31

Utah 33

Virginia 34

West Virginia 34

Wyoming 35

Chapter 5 REQUIREMENTS FOR INJECTION OF DRILLING WASTES ON FEDERAL LANDS 36

Bureau of Land Management 36

Minerals Management Service 36

Chapter 6 ACKNOWLEDGEMENTS 38

Table 1 - Summary of State Regulatory Programs for Injection of E&P Wastes 39

Appendix A - State Regulations and Other Requirements A-1

ACRONYMS, INITIALISMS, AND ABBREVIATIONS

AAC	Alabama Administrative Code
AAC	Alaska Administrative Code
AOGCC	Alaska Oil and Gas Conservation Commission
ArOGC	Arkansas Oil and Gas Commission
BLM	Bureau of Land Management
CBL	Cement Bond Log
CBM	coal bed methane
CCR	California Code of Regulations
CFR	Code of Federal Regulations
DEC	Department of Environmental Conservation (New York)
DEQ	Department of Environmental Quality (Michigan)
DMRM	Division of Mineral Resources Management (Ohio)
DNR	Department of Natural Resources (Louisiana)
DOG	Division of Oil and Gas (Illinois)
DOGGR	Division of Oil, Gas, and Geothermal Resources (California)
DOGM	Division of Oil, Gas, and Mining (Utah)
E&P	exploration and production
EOR	enhanced oil recovery
EPA	U.S. Environmental Protection Agency
ft	foot (feet)
gal	gallon(s)
GLMD	Geological and Land Management Division (Michigan)
KAR	Kansas Administrative Regulations
KCC	Kansas Corporation Commission
KDHE	Kansas Department of Health and Environment
L	liter(s)
LAC	Louisiana Administrative Code
lb	pound(s)
LNG	liquefied natural gas
LPG	liquefied petroleum gas
mg	milligram(s)
MMS	Minerals Management Service
NOGCC	Nebraska Oil and Gas Conservation Commission
NORM	naturally occurring radioactive materials
OAC	Oklahoma Administrative Code
OC	Office of Conservation (Louisiana)
OCC	Oklahoma Corporation Commission
OCD	Oil Conservation Division (New Mexico)
ODNR	Ohio Department of Natural Resources
OGCC	Oil and Gas Conservation Commission (Colorado)
OOG	Office of Oil and Gas (West Virginia)
RCRA	Resource Conservation and Recovery Act
SDWA	Safe Drinking Water Act
TDS	total dissolved solids

TRC	Railroad Commission of Texas
UIC	Underground Injection Control
USDW	underground source of drinking water
WD	water disposal
WOGCC	Wyoming Oil and Gas Conservation Commission

Chapter 1 – Introduction

Purpose of Report

Large quantities of waste are produced when oil and gas wells are drilled. The two primary types of drilling wastes include used drilling fluids (commonly referred to as muds), which serve a variety of functions when wells are drilled, and drill cuttings (rock particles ground up by the drill bit). Some oil-based and synthetic-based muds are recycled; other such muds, however, and nearly all water-based muds, are disposed of. Numerous methods are employed to manage drilling wastes, including burial of drilling pit contents, land spreading, thermal processes, bioremediation, treatment and reuse, and several types of injection processes.

This report provides a comprehensive compendium of the regulatory requirements governing the injection processes used for disposing of drilling wastes; in particular, for a process referred to in this report as slurry injection. The report consists of a narrative discussion of the regulatory requirements and practices for each of the oil- and gas-producing states, a table summarizing the types of injection processes authorized in each state, and an appendix that contains the text of many of the relevant state regulations and policies. The material included in the report was derived primarily from a review of state regulations and from interviews with state oil and gas regulatory officials.

A more detailed discussion of the mechanisms used for slurry injection is provided in a companion technical report to this regulatory compendium[1] (Veil and Dusseault 2003).

Federal Legal Background

Produced water brought to the surface along with oil and gas has been reinjected into the ground since the 1930s. At the same time, oil- and gas-producing states established permitting programs for disposal wells and repressuring projects (now enhanced oil recovery) to ensure that injection processes are protective of the groundwater, while preserving the oil field reservoirs and avoiding inefficient use of the resource. With the passage of the Safe Drinking Water Act (SDWA) in 1974, the subsurface injection of produced water came under federal regulation. In 1980, the U.S. Environmental Protection Agency (EPA) promulgated the Underground Injection Control (UIC) regulations, which govern the different types or classes of injection wells, including those associated with the production of oil and gas under Section 1422 of the SDWA. In the wake of concerns expressed by industry, as well as state oil and gas regulatory agencies, Congress amended the SDWA. Section 1425 of the SDWA gave state oil and gas regulatory agencies an opportunity to demonstrate to the EPA that their long-standing oil field-related injection control programs were of "equivalent effectiveness" to the federal UIC regulations. The oil field injection wells became known as UIC Class II wells. Most oil- and gas-producing states took advantage of the option provided by Section 1425.

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[1] Veil, J.A., and M.B. Dusseault, draft *Evaluation of Slurry Injection Technology for Management of Drilling Wastes*, prepared by Argonne National Laboratory for the U.S. Department of Energy, Office of Fossil Energy, National Petroleum Technology Office, February 2003, 100 pp.

Since then, the EPA, the states, and the regulated community at large have had considerable dialogue relative to injected liquid wastes (other than produced water) associated with oil and gas production. Produced water is the largest volume of waste generated during petroleum operations; however, other liquid, solid, and semisolid wastes are also produced when new wells are drilled. In most oil-producing states, drill cuttings, unrecoverable drilling muds, and well completion fluids are allowed to collect in pits, sealed and unsealed, and are subsequently buried in place. In 1988, the EPA made a regulatory determination clarifying that oil and gas exploration and production (E&P) wastes were exempt from the hazardous waste management requirements under Subtitle C of the Resource Conservation and Recovery Act (RCRA). The 1988 Regulatory Determination did not explicitly articulate an administrative linkage between the RCRA and UIC programs. Yet, it was acknowledged that produced water injected back into the producing reservoir for purposes of enhanced recovery would be considered a recycling activity. UIC Class II disposal wells include those injecting fluids that are brought to the surface in connection with natural gas storage operations, or conventional oil or natural gas production. Exempt E&P wastes were deemed acceptable for injection (disposal) into a Class II well. Consistent with RCRA, the 1988 Regulatory Determination and the recently updated publication titled Exemption of Oil and Gas Exploration and Production Wastes from Federal Hazardous Waste Regulations include lengthy lists of exempt waste materials, including "drilling fluids, produced wastes, and other wastes associated with the exploration, development, or production of crude oil or natural gas or geothermal energy." Although the term "slurry" is not specifically listed, one can reasonably assume that the materials listed would be present in slurries. In particular, drilling fluids and drill cuttings are most often the primary constituents of slurries. As further evidence, EPA defines "fluid" in 40 CFR Section 144.3 as "any material or substance that which flows or moves whether in a semisolid, liquid, sludge, gas, or any other form or state." Thus, slurried wastes are both RCRA exempt and Class II in nature.

<u>Types of Injection Processes</u>

Slurry injection involves mixing solid particles of suitable size with a fluid (often seawater or produced water) to create a slurry, and then injecting the slurry underground at a pressure high enough to fracture the formation receiving the slurry. When the pressure is reduced, the fluid bleeds off into the formation and the solids are trapped in place in the fractures. Other authors refer to this process as:

- slurry fracture injection (this nicely descriptive term is copyrighted by a company that provides slurry injection services, and our project team elected to use a different term to avoid copyright issues),
- fracture slurry injection,
- drill cuttings injection,
- cuttings reinjection, and
- grind and inject.

The process referred to above involves injection of slurried drilling waste above fracture pressure (slurry injection). This report and the companion technical report also describe and discuss:

- injection of slurried waste below fracture pressure (subfracture injection),

- disposal of slurried waste into the annulus between two casing strings at pressures above or below fracture pressure (annular disposal),
- disposal of drilling waste into an annulus or well bore when wells are being plugged and abandoned (plugging and abandonment), and
- disposal of wastes into salt caverns.

Use of the different forms of slurry injection has increased over the past decade, primarily in oil-producing areas such as the North Slope of Alaska, the Gulf of Mexico, and the North Sea.

One type of injection discussed in this compendium is annular disposal. While there are similarities with the other injection methods, there are also some very distinct differences that should be recognized. Annular injection is addressed by some states independent of the UIC program as an operation incidental to the drilling of a well and is therefore not a disposal operation subject to UIC. Table 1 shows which states regulate annular injection as part of the UIC program.

While slurry injection remains an unattractive option to most independent operators, one-time-event subfracture injection and annular disposal of drilling pit fluids seem more acceptable to the regulatory agencies. These practices are also more appealing to the oil and gas operators because facilities to reconstitute the drill cuttings into a true slurry texture are not needed. This decreases operational costs. However, states may impose regulatory limitations on annular disposal operations with respect to the volume of the injectate and the time frame of the disposal activity. Proper design and management of annular disposal is critical to ensure that the fluids are contained to the receiving zone.

Chapter 2 – Barriers to the Use of Slurry Injection

Extensive literature exists on the technical merits of slurry injection. Over the past decade, slurry injection has proved a viable technology in the North Slope, the North Sea, and in other locations around the world. However, slurry injection has not been a top option for disposal of drill cutting and other E&P wastes in the producing areas of the Continental United States. This study identifies economic and regulatory barriers that may explain the reasons why slurry injection and other forms of drilling waste injection have not been used more commonly.

Economic Barriers

In nearly all onshore oil and gas-producing areas of the United States, the most commonly used means of drilling waste management is removal of liquids resulting from dewatering the drilling mud pits and burial of the remaining pit contents in place. State agencies have supported this practice, and the costs to manage wastes through burial are lower than most other disposal options. Currently, operational costs appear to pose a major barrier to the extended use of slurry injection technology at most of the drilling locations in mature onshore producing areas, such as Kansas, Oklahoma, and the Appalachian states. Interviews revealed the surprise of several state regulators that independent operators would want to use slurry injection, while burial of E&P wastes and proper closure of drilling and reserve pits are cheaper, because facilities to reconstitute the drill cuttings into a true slurry texture are not needed. In sum, the cost of slurry injection facilities in the context of typical independent onshore oil and gas lease operations poses a significant barrier to the expanded use of the technology, especially in areas where burial of drilling wastes in pits is acceptable. In addition, the historically accepted practice of pit burial constitutes a cultural barrier too.

In certain offshore areas discharges are prohibited, or the muds, cuttings, and produced water will not pass the required standards of a National Pollutant Discharge Elimination System (NPDES) permit for discharge to the marine environment. In such cases, operators of offshore production sites are required to transport the materials to a shore location for treatment and disposal. Thus, in the Gulf of Mexico, several commercial waste disposal companies have established networks of facilities to receive wastes from offshore and transport them in bulk to centralized disposal sites. One company utilizes subfracture injection, while the other uses salt cavern disposal. The costs of this service are moderate enough that most operators in the Gulf of Mexico have not chosen to employ onsite slurry injection. In Cook Inlet, the NPDES permit for produced water and water-based muds and cuttings allows discharge to the marine environment. Oil-based drilling waste is disposed of by slurry injection at platforms where a Class II well or annulus is available, or it is hauled to a platform that has a Class II well. In other parts of the world that do not have the luxury of dedicated disposal networks or NPDES-type management options, slurry injection becomes more attractive.

The environmental and geological settings (e.g., rock properties in receiving zone, freshwater aquifers) in a given area may favor or advise against slurry injection. Most slurry injection projects are conducted in areas of the United States and the world where environmental concerns and geological settings would preclude the traditional in situ burial of waste in pits. The North Slope of Alaska is a prime example of a situation in which the traditional waste management options are not available or appropriate. To protect the highly sensitive North Slope environment, the operators have selected innovative slurry injection processes that remove the wastes from contact with soils and surface water and remove them from the biosphere. (It is also important to note that the large-scale slurry injection projects on the North Slope, although highly environmentally acceptable, are the result of a lawsuit brought against ARCO Alaska for violations of the Clean Water Act. The decision to move forward with such technology (grind and inject) was driven by the permanent nature of the slurry injection solution -- as opposed to the liability for potential excavation with burial options.) In other areas with different environmental and geological settings, the picture may be quite different.

Regulatory Barriers

The EPA's Class II UIC regulations do not specifically prohibit slurry injection. However, the Class II regulations specify that the initiation of new fractures and the propagation of existing fractures must occur within the injection formation. Moreover, the fracturing must not extend to the confining zone or cause migration of fluids into an underground source of drinking water (USDW).

The primary regulatory barrier to the use of the slurry injection option stems from the limitation on wellhead injection pressures imposed by the Class II UIC primacy agreements between the EPA and the authorized states. The Class II UIC regulations, administered under Section 1422 or Section 1425 of the SDWA, pose more of a barrier because of interpretation than wording of regulations or guidance. Most State-EPA Agreements on program primacy were entered into prior to the development of slurry injection technology. One of the cornerstones of the UIC program is to discourage artificially applied wellhead pressure that could cause a breach in the confining bed above the injection zone or create conduits for injected fluids to migrate into USDWs.

In those states that have not received delegation of the UIC program, the EPA has allowed operators to dispose of wastes at drilling site locations into the well upon completion or abandonment, so long as the injection zone was able to accept the fluid, or slurry under the column of hydrostatic pressure. The EPA has indicated that it would consider applied pressure requests and slurry injection if operators furnished proof through geologic evidence or reservoir studies that the confining zone above the injection formation would not be breached. State-run UIC programs are at least as restrictive as direct implementation programs. For example, in Alaska, reviews encompass detailed confinement analysis to ensure no breach of the confining layer. Moreover, Alaska regulations require protection of all freshwater (defined as having total dissolved solids < 10,000 ppm), while EPA criteria focus on the protection of underground sources of drinking water. Relative to pressures exceeding the fracture pressure both the EPA and many states retain a cautious posture.

In many older producing areas with little documentation relative to the locations of pre-1940 oil and gas tests, core holes, and stratigraphic tests, produced water injection has caused formation fluids to migrate up unplugged and poorly plugged holes. An occasional phenomenon was the stair-step effect when produced water was injected into a deeper zone under such pressure that fluid rose in a nearby, unplugged hole and triggered overpressurization of an artesian aquifer closer to the surface. Occasionally, several confined sand intervals at different depths above the injection zone have been involved in the upward migration. As a result, unwanted flows of mineralized water into surface streams or unconfined aquifers along the subcrop have occurred. In a paper presented at the September 2002 Ground Water Protection Annual Forum, the Louisiana UIC director reported that his agency had observed several cases each year for the past few years of injected slurries that had breached to the surface.[2] The breaches had occurred during reserve pit annular injection (disposal) operations. The Louisiana agency responded to this problem by developing new, more comprehensive regulations for annular disposal.

These types of events have prompted the regulatory agencies to reduce allowable wellhead injection pressures to between 0.5 and 0.9 pounds per square in per foot (psi/ft) of depth. The pressures necessary for the injection of slurry regularly exceed these standards considered arbitrary by some and acceptable by others.

A different sort of regulatory barrier can be found in Kazakhstan, where the Kazakhstan Petroleum Law outlaws offshore and onshore burial of offshore-generated E&P wastes. Currently, these wastes must be transported to a shore facility for further management involving practices other than burial. Companies and operators in the Caspian Sea region are presently considering the use of slurry injection technology. However, slurry injection facilities may be authorized only if the regulatory officials are persuaded that injection is not a subset of burial.

[2] Wascom, C., and G. Snellgrove, "Annular Disposal of E&P Wastes: A Louisiana Perspective," presented at the Ground Water Protection Council Annual Forum, San Francisco, California, September 22-25, 2002.

Chapter 3 – Overview of Injection Requirements and Practices

Slurry Injection

Slurry injection is currently permitted on a regular basis in Alaska, Texas, and California. California, Wyoming and Oklahoma allow injection pressures to exceed the fracture pressure; however, Wyoming and restrict the amount of fluid or slurry injectate to a single-well situation. In those cases, only the waste from the well of origin can be reinjected. Louisiana has recently promulgated specific rules for slurry injection. Amendments governing the disposal of reserve pit fluids are in draft stage. In the past, Louisiana has allowed slurry injection as an experimental technology on a case-by-case basis. California regulation is based on the supposition that an applicant can obtain permission to use slurry injection technology if geologic conditions and other factors confirm that the confining beds will not be breached and that USDWs will not be threatened. California often uses the experimental-project approach. The regulatory availability of slurry injection appears to coincide with those areas in the United States that exhibit environmental, geological, or hydrogeological circumstances that pose regulatory barriers relative to the disposal of drilling wastes into pits. Examples include tundra or shallow water tables. Oil and gas regulatory officials from the mid-continent states tended to indicate minimal interest in slurry injection. A few state regulators expressed concerns that formation fractures could develop in the confining beds without a possibility to ascertain the route of fluid migration.

Subfracture Injection

Most oil- and gas-producing states exercise the regulatory authority to allow disposal of drilling fluids and wastes by injection back into their wells of origin. In the context of wells approved for annular disposal, most state agencies limit the volume of injectate by restricting the activity to a one-time disposal process. Only Indiana, by policy, prohibits any injection of drilling wastes except as can be used for spacers in well plugging operations. Several states indicated that state water protection agencies and water planners would express their skepticism with respect to the application of injection pressure necessary to fracture the target formation—even without fracturing any confining beds. As previously discussed, State-EPA Agreements on UIC program primacy determine the amount of pressure allowed when injecting slurry.

None of the surveyed states except Texas indicated that dedicated wells were being used for the injection of drilling wastes at subfracture injection pressures. One commercial disposal company located in eastern Texas has received authority from the Railroad Commission of Texas (the oil and gas regulatory agency) to inject tens of millions of barrels of offshore waste into naturally fractured cap rock on the flanks of a salt dome. The injection pressures are low and on some occasions, the waste is drawn into the formation under a vacuum.

Annular Injection

Annular injection of drilling wastes is allowed by a significant percentage of state oil and gas regulatory agencies. Several states, including Kansas, Mississippi, Alabama, Illinois, Louisiana, Texas, and Alaska, permit annular injection of drilling waste. Annular injection is governed by regulation and policy. Some states, like Alaska, regulate annular disposal separately from UIC disposal. Others, like Alabama, use UIC Class II regulations. The survey indicated the following regarding annular injection regulatory attitudes.

(1) Except for Alaska, states and the EPA limit the volume of injected waste to the drilling wastes generated by the well of origin. The State of Alaska allows wastes from other well locations to be brought in but requires documentation relative to the waste, including its point of origin, description, and date(s) of generation. Alaska does limit both the volume (35,000 bbls maximum) and timeframe (90 days total within one year from initiating the operation) for annular disposal.

(2) Annular injection is permitted only in wells that have surface casing and cementing to a specified depth below the base of the lowermost USDW. That depth ranges from 200 to 500 ft below the USDW (and varies by state). The extent of protected interval depends more upon the state's disposition. Some states may favor limited annular injection.

(3) Most states and the EPA view annular injection as a short-term event, with a permitted disposal window ranging from 30 to 120 days. This depends upon the state regulations governing closure of the reserve pit or upon the official completion date of the well. By comparison, Alaska limits the injectate volume to 35,000 barrels and limits the actual injection to 90 days total to be completed within 1 year from initiating the operation.

(4) States have different standards for establishing an approved injection pressure magnitude. The location of the pressure measurement is not always clearly defined. The pressure may be measured at the wellhead or at the bottom of the well. The bottom hole pressure will always be larger as it includes the pressure caused by the weight of the fluid column and other pressures associated with frictional losses. Alabama's approved maximum injection pressures are based on 90% of the test pressure applied to demonstrate mechanical integrity. In Alaska, the operator is required to determine the strength of the formations exposed below the surface-casing shoe. The allowed annular disposal pressure shall not exceed the downhole pressure obtained during the formation integrity test conducted below the outer casing shoe unless a higher pressure is specifically approved. In North Dakota, the guidelines for true annular disposal provide that the disposal pressure cannot exceed 75% of pressure test on surface casing, which must be pressure tested to 80% of burst pressure rating after drilling is completed and prior to running production casing. If the surface casing pressure test fails, no injection is allowed.

(5) The practice of annular disposal in Ohio is somewhat unconventional. While Ohio Oil and Gas Law does not prohibit annular disposal of brine and associated waste generated during drilling or completion operations, in practice annular disposal wells have been used exclusively for produced water. Unlike other states where the practice appears to be limited to short-term disposal of drilling wastes, Ohio allows annular disposal of brine throughout the productive life of a well. Ohio rules require cementing of the surface casing, verification of cement returns, passage of an initial mechanical integrity test, and subsequent mechanical integrity tests every five years. On average no more than ten

barrels of brine can be disposed daily, and pressure at the wellhead is restricted to hydrostatic.

Plugging and Abandonment

Several states allow the injection of drilling pit wastes and reserve pit wastes back into the well of origin prior to abandonment. Some states, including Texas, Oklahoma, and Wyoming, allow pressures exceeding the fracture pressure, while several others use the upper pressure limit allowed for injection of produced water under the Class II UIC program. No across-the-board standard exists for the maximum allowable pressure; individual state limitations range from 0.5 to 0.9 psi/ft of depth. Most states do not consider this category separate from the subfracture or fracture injection processes described above. They view this process as a part of plugging and abandonment rather than injection.

Salt Cavern Disposal

In the United States, disposal of drilling waste into salt caverns is currently permitted only in Texas, although Louisiana is in the process of developing cavern disposal regulations. Cavern disposal operation in Texas appears to be very successful. As of August 2002, 11 caverns have been permitted at 7 locations.[3] All of these caverns may receive E&P wastes, including drilling wastes, and 3 of them may also receive naturally occurring radioactive material (NORM). Other states, including Alabama, Kansas, Michigan, Mississippi, New York, and Oklahoma have considerable salt deposits, which have been used for solution mining of salt and for cavern storage of hydrocarbons. None of these states, however, has seriously considered the use of salt caverns for waste disposal.

Disposal in Coal Mines

Old coal mines have been used in some instances for disposing of solid wastes, such as fly ash. Several states have coal bed methane (CBM) or oil production in the areas with coal deposits. Because of the recent surge in CBM drilling and production, state officials were surveyed to learn if any drilling wastes are being disposed of in coal mines. According to oil and gas regulators, however, coal mines have never been used for the disposal of oil field or E&P wastes except in Virginia. This practice has been directly approved on a case-by-case basis by the EPA under Section 1422 of the SDWA.

[3] Personal communication between R. Ginn, Railroad Commission of Texas, Oil and Gas Division, Austin, Texas, and J. Veil, Argonne National Laboratory, August 8, 2002.

Chapter 4 – State Requirements and Practices for Injection of Drilling Wastes

This chapter contains a summary of responses from each state contacted during the survey. Some states were contacted more than once when further explanation or discussion was essential to understanding the program.

About half of the states were sent a list of questions by e-mail and were later contacted by phone to complete the information profile. The rest were interviewed by phone to complete the profile. The state personnel contacted and the dates of phone interviews are shown as footnotes, although in some instances, relevant conversations may have also occurred in the hallways at professional conferences. Some of the regulatory agencies cited specific regulations or policies. Where possible, these source documents were obtained through e-mail, fax, or the worldwide Web, and are compiled in Appendix A.

Table 1 provides a summary of the E&P waste injection programs for each state.

Alabama

The Alabama Oil and Gas Board (the Board), under the direction of the State Geologist and the Oil and Gas Supervisor, is responsible for the regulation of oil and gas operations. The administration of field operations is divided into three regions—north, south, and offshore. The Board has received Class II program primacy from EPA Region IV under Section 1425 of the SDWA.

The Board allows the injection of drilling waste from reserve pits into the surface casing-production casing annulus of a newly completed well and into the open-hole well bore of a newly drilled dry hole prior to plugging. The cited rules on the subsurface disposal of pit fluids are as follows: onshore conventional (400-1-4-.11), onshore coal bed methane (400-3-4-.11), and offshore (400-2-4-.10). Both onshore rules are entitled "Recycling or Disposal of Pit Fluids and Pit Closure;" the offshore rule is entitled "Recycling or Disposal of Tank Fluids." The mechanical integrity of the casing is used to establish the maximum pressure allowed to be applied during the injection of wastes. The surface casing is retested to demonstrate mechanical integrity upon conclusion of drilling operations or before running the next casing string. During disposal of drilling waste, Alabama's approved maximum injection pressures are based on 90% of the test pressure applied to demonstrate mechanical integrity. The Board approves the injection of drilling wastes for the well of origin. This applies to statewide operations. Applications filed by an operator are administratively approved based on compliance with provisions set forth in regulations. Approval requires a determination that the proposal will be protective of USDWs. Landowners and adjoining offset operators are generally not notified.

Salt cavern disposal could conceivably become an option in Alabama, although it is not planned at this time. The state hosts the large McIntosh dome, which is used to store natural gas in salt cavities at two project locations. No request from operators to develop salt cavern disposal facilities for oil and gas waste has been made. It should be noted that the Alabama Department of Environmental Management would also be involved in the decision process, because they regulate Class III solution mining operations associated with cavity development.[4]

Alaska

The Alaska Oil and Gas Conservation Commission (AOGCC) administers oil and gas regulations governing production of oil and gas, principles of oil and gas conservation, underground injection of produced water and other E&P wastes, and pollution control facilities used for environmental and water resource protection. The Alaska Department of Natural Resources, Oil and Gas Division, is responsible for leasing state lands for oil and gas exploration. The agency implements programs that encourage exploration and development activities on state and private lands. A third agency, the Alaska Department of Environmental Conservation, has the authority to regulate and enforce proper management practices for hazardous wastes generated, stored, or transported by the oil and gas industry. The AOGCC has UIC Class II primacy from EPA Region X under Section 1425 of the SDWA. The EPA administers the UIC Class I program through Region X pursuant to Section 1422 of the SDWA. The State of Alaska has 58 active Class II-D (disposal) wells and six Class I wells. All Class I wells are located on the North Slope: three at Prudhoe; one each in the Northstar, Alpine, and Badami fields. (Note: EPA also manages all other UIC well classes under its Direct Implementation; Alaska only has jurisdiction for Class II.)

Alaska has developed a regulatory program for underground disposal (including slurry injection) and annular disposal of drilling waste. Alaska, like some other states, regulates annular disposal separately from UIC disposal. Both processes are used throughout the producing areas of Alaska, including the North Slope, the Kenai Peninsula, and the offshore areas of the Cook Inlet. The fragile ecosystem of the North Slope, the offshore production of the Cook Inlet, and the glacial stratigraphy of onshore producing areas make injection of oil and gas waste a viable and environmentally acceptable alternative to pit burial. Because of the production quantities and the sensitive Alaskan environment, expensive ball mill facilities have been established to grind drill cuttings and other solid oil field waste. The wastes are mixed with water into a slurry consistency and are then injected. Slurry injection can involve fracturing of the injection formation.

The first regulation, which applies to slurry injection, is found in Title 20, Chapter 25, Section 252 of the Alaska Administrative Code (20 AAC 25.252), entitled "Underground Disposal of Oil Field Wastes and Underground Storage of Hydrocarbons." The regulations were promulgated in 1986, and were revised in 1996 and 1999. According to the regulations, the operator must file a letter of application with the AOGCC and demonstrate that the proposed disposal will not allow the movement of oil field wastes into sources of freshwater. Moreover, the disposal wells must be cased and the casing cemented to isolate the disposal zone and protect oil, gas and freshwater. The information required for a Class II subfracture injection well is similar to any standard UIC application. Furthermore, a mechanical integrity test is required prior to disposal. Retesting must be conducted at least once every four years. The operator must monitor the injection

[4] Personal communication between R. Raymond, Alabama Oil and Gas Board, Tuscaloosa, Alabama and B. Bryson, Argonne National Laboratory, November 27, 2001; personal communication with D. Bolin, Alabama Oil and Gas Board, Tuscaloosa, Alabama, and B. Bryson, Argonne National Laboratory, September 23, 2001.

pressure and rate as well as the pressure in the casing-tubing annulus during actual disposal operations. Slurry injection applications are judged on a case-by-case basis. The allowable pressures necessary for drilling slurry injection may change as experience accrues. In practice, most wells authorized for slurry injection also have more stringent operational criteria, such as mechanical integrity tests every two years, baseline temperature surveys, yearly step-rate testing, and annual performance report submission (including rate and pressure performance, surveillance logging, fill depth, survey results, and volumetric analysis of the disposal storage volume, estimate of fracture growth, if any, and updates of operational plans).

Separate regulations governing the annular disposal of drilling waste are found in Title 20, Chapter 25, Section 080 of the Alaska Administrative Code (20 AAC 25.080), entitled "Annular Disposal of Drilling Waste." An operator holding a permit to drill a well may dispose of drilling waste through the well's annular space after filing with the AOGCC an Application for Sundry Approvals, supplemented with additional information required by the regulations. The operator may refer to information already on file with the AOGCC; however, a rather detailed description of the formations open to the annulus is required. In addition, the maximum anticipated pressure at the outer casing shoe during operations must be estimated and the manner of pressure calculation must be demonstrated. Some other features of the regulation include:

- Approval is given for one year, with a 90-day limit on actual injection. Upon proper demonstration that "compliance with the limitation is imprudent," the approval period may be increased to over one year. The same applies when an operator seeks an injectate volume of greater than 35,000 barrels into the annular space of a single well, through an annular space not located on the same drill pad or platform as the drilling operation generating the waste, and injection into a hydrocarbon-bearing stratum.

- If drilling waste has been disposed of in the annular space of a well, a summary of the point of origin (well or wells), the volumes, and the date of disposal must be provided. The AOGCC requires reporting of annular disposal volume, date/duration, and well information within 30 days of completing authorized disposal. A specific report form is being developed.

- The types and volumes of the waste as well as the density of the slurry must be indicated.

- The downhole disposal pressure may not exceed the downhole pressure obtained during the formation integrity test conducted below the outer casing shoe, or a higher pressure specified in the authorization upon the AOGCC's finding that the higher pressure will not cause drilling waste to migrate above the confining zone.

- In addition to ensuring that the injection will not contaminate freshwater, cause drilling waste to come to the surface, impair well integrity, damage a producing zone or potential producing zone, the operator must prove that annular injection is not being used to circumvent 20 AAC 25.252. Guidance provided by the EPA to the State of Alaska has stated that annulus injection is not covered under the UIC program unless the practice is abused to circumvent the intent of the UIC program. [5] The EPA has explained that it considers abuse to occur when one well is used excessively. [6]

Arizona

Oil and gas operations in Arizona are regulated through the Arizona Geological Survey, which provides administrative and staff support to the Arizona Oil and Gas Conservation Commission. In Arizona, no requests have been received for the use of slurry injection technology. Determinations would be made on a case-by-case basis.[7]

Arkansas

The Arkansas Oil and Gas Commission (the ArOGC) in Eldorado, Arkansas, administers the oil and gas regulations. The Director of Production and Conservation is the Chief Executive of the ArOGC and is the supervisor of regulatory activities. Arkansas is treated as a single administrative region except for field activities and inspections in the northwestern Arkansas dry gas area, which are conducted out of the Fort Smith office.

The ArOGC allows subfracture injection and annular injection of slurries of drilling wastes and contaminated soils containing naturally NORM. Arkansas classifies all wells used for slurry injection as Class II wells and imposes the requirements applicable to produced water injection wells. Arkansas has received UIC program primacy under Section 1425 of the SDWA.

The UIC Director for Arkansas indicated that the state has not received many requests to inject slurries waste because this is a costly process. While the defined upper limit of allowable total dissolved solids (TDS) for USDWs is 10,000 milligrams per liter (mg/L), the cemented surface pipe protection in the case of slurry injection has to cover all aquifers with TDS content up to 3,500 mg/L. In a dedicated well or dry hole, drilling wastes must be injected at pressures not to exceed 0.5 psi/ft of depth. In the annulus of a producing well, drilling wastes may be injected at 75% of the mechanical integrity test pressure for the well (generally tested just after the casing shoe is drilled). The operator has 30 days to use the annular option starting from the spud date of the well.

The ArOGC has developed administrative hearing procedures that can be invoked by an operator who wishes to use an alternative drilling waste disposal technology *in lieu* of burial in closed pits. The ArOGC uses the hearing process to address the disposal of drilling wastes in sensitive groundwater areas. Arkansas has no salt deposits amenable to the disposal of oil and gas E&P wastes.[8]

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[5] Personal communication between W. Mahan, ConocoPhillips, and J. Veil Argonne National Laboratory, November 27, 2002.
[6] Personal communications between T. Maunder, Alaska Oil and Gas Conservation Commission, Anchorage, Alaska, and B. Bryson, Argonne National Laboratory, December 19, 2001, January 13, 2001, and January 22, 2002.
[7] Personal communication between S. Rauzi, Arizona Oil and Gas Conservation Division, Tucson, Arizona, and B. Bryson, Argonne National Laboratory, March 5, 2002.
[8] Personal communication between G. Black and G. Looney, Arkansas Oil and Gas Commission, El Dorado, Arkansas, and B. Bryson, Argonne National Laboratory, November 2, 2001.

California

The Division of Oil, Gas, and Geothermal Resources (DOGGR) in the California Department of Conservation is directed by the State Oil and Gas Supervisor. The DOGGR, headquartered in Sacramento, operates six district oil and gas offices. Certain responsibilities overlap with the California State Land Commission and the U.S. Bureau of Land Management with respect to drilling, production, inspection, and administration on government-owned lands. The DOGGR administers the Class II program under a primacy agreement with EPA Region IX. California is the only oil- and gas-producing state that does not recognize the federal E&P exemption under RCRA.

California has permitted slurry injection operations under its general rule in Title 14, Division 2, Chapter 4, Article 3, Section 1722 (k) of the California Code of Regulations (CCR), entitled "General." This regulation states as follows:

> (k) When sufficient geologic and engineering information is available from previous drilling, operators may make application to the supervisor for the establishment of field rules, or the supervisor may establish field rules or change established field rules for any oil or gas pool or zone in a field. Before establishing or changing a field rule, the supervisor shall distribute the proposed rule or change to affected persons and allow at least thirty (30) days for comments from the affected persons. The supervisor shall notify affected persons in writing of the establishment or change of field rules.

The DOGGR also approves slurry injection operations using the federal UIC regulations that give the state administrator (State Oil and Gas Supervisor) the authority to approve additional fluids as Class II-type fluids, with the consent of the EPA.

Section 1724 *et seq.* of the CCR contains the state UIC regulations. Pursuant to Section 1425 of the SDWA, California has received Class II program primacy under agreement with EPA Region IX. According to the DOGGR's senior engineer handling rule interpretation, all slurry injection projects are permitted under Section 1722 (k) and through EPA primacy. Proposals are approved on a case-by-case basis as experimental projects. The DOGGR has permitted two wells as pilot projects; however, after a period of one year the classifications were changed. The experimental-project approach allows for the flexibility needed to fit the injection of drilling wastes into the proper geologic setting. Two "grind and inject" operations were approved as a pilot program. Others, classified as experimental efforts, were permitted for slurry injection based on the information gained from the pilot projects. The UIC regulations, which are used as a model for any submitted engineering study, provide for a range of reservoir and well completion criteria that can be used to assess each application.

A significant issue for slurry injection in California is associated with language in Section 1724.10(i). It states:

> Test pressure shall be from hydrostatic to the pressure required to fracture the injection zone or the proposed injection pressure, whichever occurs first. Maximum allowable surface injection pressure shall be less than the fracture pressure. The appropriate district

office shall be notified prior to conducting the test so that it may be witnessed by a division inspector. The district deputy may waive or modify the requirement for a step-rate test if he or she determines that surface injection pressure for a particular well will be maintained considerably below the estimated pressure required to fracture the zone of injection.

In California, all slurry injection wells are considered to be in UIC Class II. Annular injection wells are not permitted in California. The DOGGR has permitted two slurry-disposal wells in the Long Beach area (one well is shut in) and two wells (one EOR and one WD) in the Ventura area. The UIC regulations on formation fracturing are more stringent than those administered directly by the EPA.

California hosts no salt caverns for disposing of oil and gas E&P wastes.[9]

Colorado

The Oil and Gas Conservation Commission (OGCC), which is a branch of the Department of Natural Resources, regulates oil and gas activities in Colorado. Colorado is treated as a single geographic region for oil and gas regulation; however, inspectors and engineers are located at other points throughout the state to carry out inspection and enforcement activities. The Deputy Director of the OGCC indicated that the state had received no requests for slurry injection, subfracture injection, or annular disposal of drilling wastes. Operator requests would be administratively approved or denied on a case-by case basis. Colorado has not promulgated regulations for the injection of wastes other than for produced water. The state enjoys Class II program primacy pursuant to Section 1425 of the SDWA. Colorado contacts did not provide any details with respect to an unsuccessful trial pilot project for pressurized injection of drilling and reserve pit contents that was conducted about eight years ago. Since that time, the state has not encouraged operators to inject drilling wastes into wells.[10]

Florida

Oil and gas operations in Florida are regulated by the Florida Geological Survey (FGS), which is part of the Florida Department of Environmental Protection (FDEP). Construction and operation of Class II wells in Florida require permits from both the USEPA and the FDEP. EPA Region IV administers Florida's Class II program under Section 1422 of the SDWA. Region IV has allowed subfracture injection in other states (e.g., Kentucky), but no requests have been received for Florida. Relevant FDEP rules are contained within Chapters 62C-25 through 30, Florida Administrative Code. Generally, the authorization to inject drilling fluids into drilled wells is contained within the Permit to Drill, although each operation is considered on a case-by-case

[9] Personal communications between M. Stettner, California Department of Conservation, Division of Oil, Gas and Geothermal Resources, Sacramento, California, and B. Bryson, Argonne National Laboratory, September 19, 2001, December 9, 2001, and January 14, 2002.

[10] Personal communication between B. Macke, Colorado Oil and Gas Conservation Commission, Denver, Colorado, and B. Bryson, Argonne National Laboratory, November 27, 2001.

basis. At present, Florida offshore areas are off-limits to drilling; thus, facilities for drill cutting processing or conversion into a slurry have not been needed.[11]

Illinois

The Division of Oil and Gas (DOG), Department of Natural Resources, is responsible for regulating all aspects of oil and gas operations in Illinois. The state is treated as a single geographic region for purposes of administering the oil and gas regulations. The DOG also administers the Class II program under Section 1425 of the SDWA. The state has a primacy agreement through EPA Region V.

Illinois does not have specific regulations, directives, or policy statements relative to slurry injection, subfracture injection, or annular injection of drilling waste, and would handle requests from operators on a case-by-case basis. In addition, no salt caverns or coal mines have been used for disposal of wastes. The DOG Director indicated that if the state received requests from operators to use drilling pit wastes for interplug fluids (spacers) during well plugging operations or for injection down the production-casing annulus of newly completed producing wells, these requests would be approved or denied on a case-by-case basis. If approval is given, the DOG inspectors must be notified to witness the injection event. The DOG did promulgate a 45-day rule for injection of production pit waste (such as bottom sediment). The rule was adopted to provide a mechanism for cleaning up the large number of production pits without having to haul the waste to a commercial facility or permitted Class II well location. From the time of approval, an operator has 45 days to inject the drilling wastes down the annulus through tubing. After 45 days, the injection approval is withdrawn and the well must be plugged. The injection pressures normally allowed for Class II wells (0.8 psi/ft of depth) are regularly used for annular injection of drilling waste. Operators have the opportunity to request a variance from requirements, but must furnish the DOG with compelling supporting evidence.[12]

Indiana

The Division of Oil and Gas, Department of Natural Resources, administers the oil and gas regulatory program in Indiana. Indiana is treated as a single geographic administrative region. The state has obtained primacy for a Class II program from the EPA pursuant to Section 1425 of the SDWA. Indiana has not promulgated regulations for slurry injection or subfracture injection. Pursuant to its UIC regulations, the state does not permit annular injection of any E&P waste. All injection of produced water or other E&P liquid waste must be made through tubing and packer. The UIC Director indicated that before any E&P waste, other than produced water, was injected into a well, EPA Region V would have to determine whether the process came under Class II (administered by the state) or Class V (administered directly by the EPA).

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[11] Personal communication between D. Curry, Florida Geological Survey, Tallahassee, Florida, and B. Bryson, Argonne National Laboratory, March 5, 2002.

[12] Personal communication between L. Bengal. Illinois Department of Natural Resources, Office of Mines and Minerals, Division of Oil and Gas, Springfield, Illinois, and B. Bryson, Argonne National Laboratory, December 27, 2001.

Indiana allows drill cuttings to be injected through tubing as a spacer material between plugs during the plugging of any well drilled for oil and gas purposes (dry hole), provided that the casing has been cemented through or removed 50 ft below the lowest (all) USDW. Indiana has the regulatory flexibility to approve technologies on a case-by-case basis after the operator gives valid proof that USDWs will not be threatened.[13]

Kansas

The Kansas Corporation Commission (KCC) Oil and Gas Conservation Division (the OGCD) regulates most of the oil and gas operations in Kansas, including the administration of the Class II program. The OGCD's main office is located in Wichita and the KCC's main offices are in Topeka. In addition, the OGCD maintains four district offices throughout the oil- and gas-producing areas. They have authority to administratively approve certain practices related to pit closure and plugging of wells. The districts are also in charge of inspections, UIC testing and monitoring activities, plugging supervision, and first line enforcement. The KCC received UIC Class II delegation from the EPA in 1984 and has responsibility for onsite disposal of E&P wastes and cleanup of oil field related contamination of soils. The Kansas Department of Health and Environment (KDHE) regulates the salt solution mining industry (UIC Class III) and the storage of hydrocarbons in salt caverns. By interagency agreement, the KDHE regulates off-site remediation of past (abandoned) site contamination. However, for all practical purposes, KCC would be the agency overseeing the removal of fluids and solids from drilling and reserve pits prior to closure.

The KCC Class II program is contained in Agency 82, Article 3, Sections 82-3-400 *et seq.* of the Kansas Administrative Regulations (KAR). Under these regulations, OGCD staff does not allow slurry injection administratively. Therefore, operators have to seek an approval hearing before the KCC. Section KAR 82-3-100 allows the KCC to grant a waiver from a regulation if the operator provides sufficient proof that the requested technique will not be deleterious to water and environmental resources or injurious to the producing zones. Each slurry injection request requires a hearing unless the KCC promulgates a specific regulation for slurry injection monitoring, record keeping, and injection rates and pressures. The Class II UIC Director indicated that no slurry injection requests had been received during his 18 years of service with the KCC.

The KCC has allowed one-time disposal of E&P wastes, including drill cuttings, down the annulus of a producing well. The process is treated as injection and the injection pressure is limited to 0.7 psi/ft of depth. This reflects the standard used in the State/EPA Agreement for all Class II wells approved since 1984. The operator is required to notify the appropriate district office when injection occurs and file a report relative to the amount of injectate and the pressure applied during injection. Only wastes from the well of origin qualify for injection. KCC policy prohibits using the annulus of one well as a centralized disposal location for wastes from other wells or lease locations. The KCC indicated that most subfracture injection requests came from areas where shallow groundwater tables dictated the use of closed systems for catchment of drill cuttings *in lieu* of pits. Subfracture injection is rarely requested for plugging and abandoning

[13] Personal communication between M. Nickolaus, Indiana Department of Natural Resources, Division of Oil and Gas, Indianapolis, Indiana, and B. Bryson, Argonne National Laboratory, November 27, 2001.

activities, and drill cuttings are not often used as a spacer between plugs during the plugging of a well.

Central Kansas has had extensive development of its 300 ft bedded Hutchinson salt section (the Permian-Wellington formation) for storage of liquefied petroleum gas (LPG), liquefied natural gas (LNG), and more recently, natural gas. In 1997, the KCC was approached by an environmental geologist about the possibility of obtaining a special permit to use an existing salt cavern for disposal of Class II E&P waste. The cavern had previously been an LPG storage location. As a result of discussion between the KCC and the KDHE, the operator would have had to assume liability for any previous defects in the LPG cavern, and reduced stability of the salt roof and integrity of the cavern due to improper solutioning of the upper salt. In addition, the KCC and the KDHE would have had to strike some agreement governing institutional responsibility during cavern operation and upon cavern abandonment relative to the disposal of KCC-regulated waste. The bedded nature of the Kansas salt deposits may be more conducive to oil field waste disposal than for pressurized hydrocarbon storage.[14]

Kentucky

All oil and gas regulations in Kentucky, except for the rules governing the surface discharge of brines and UIC, are administered through the Division of Oil and Gas (the DOG), Department of Mines and Minerals. Kentucky is treated as a single geographic administrative region. EPA Region IV directly administers the Class II program under Section 1422 of the SDWA.

Kentucky has no statutes, regulations, or policies that specifically address slurry injection, subfracture injection, and annular injection of drill cuttings. According to the DOG Director, the state does not issue duplicate UIC permits. However, the EPA has allowed at least one operator to dispose of drilling waste down the annulus of a producing well on a one-time basis. The EPA conditioned the approval on a verification that the injection pressure did not exceed the pressure that is furnished naturally by the hydrostatic head. The DOG, like similar agencies in most states, enjoys rather broad administrative approval powers to address new technologies. Kentucky does not have the jurisdiction over any slurry injection requests, because the authority to issue the permit rests with the EPA.[15]

Louisiana

The Louisiana Department of Natural Resources (DNR), Office of Conservation (OC), is responsible for regulating all oil and gas activities in the state. The Office of Conservation consists of five divisions, including the Geological Oil and Gas Division and the Injection and Mining Division. Field inspection and enforcement activities for injection wells, disposal wells, and commercial E&P waste treatment and disposal facilities are carried out by field agents within the Injection and Mining Division (through three district offices). In 1982, Louisiana

[14] Personal communications between M. Korphage and A. Snider, Kansas Corporation Commission, Conservation Division, Wichita, Kansas, and B. Bryson, Argonne National Laboratory, August 26, 2001, and October 16, 2001.
[15] Personal communications between R. Bender, Kentucky Department of Mines and Minerals, Oil and Gas Division, Frankfort, Kentucky, and B. Bryson, Argonne National Laboratory, September 23, 2001, and October 31, 2001.

obtained Class II UIC program authority from EPA Region VI under Section 1425 of the SDWA. In 2001, the DNR OC undertook a major overhaul of several sets of regulations governing oil and gas waste management. These are all contained in Title 43 (Natural Resources), Part XIX (Office of Conservation), Subpart 1 (Statewide Order No. 29-B) of the Louisiana Administrative Code (LAC):

- Finalized Addition of new regulations in Chapter 4 of Statewide Order No. 29-B, LAC 43:XIX.433, entitled "Disposal of E&P Wastes by Slurry Fracture Injection."

- Finalized Amendment to Chapter 5 (Off-site Storage, Treatment and/or Disposal of Exploration and Production Waste Generated From Drilling and Production of Oil and Gas Wells) of Statewide Order No. 29-B (LAC 43:XIX.501 *et seq.*).

- Draft Amendment to Chapter 3 (Pollution Control, On-site Storage, Treatment and Disposal of Nonhazardous Oilfield Waste (NOW) Generated from the Drilling and Production of Oil and Gas Wells (Oilfield Pit Regulations), LAC 43:XIX.301 *et seq.*). Section 315 is entitled "Disposal of Reserve Pit Fluids and other E&P Wastes by Slurry Fracture Injection." The original title was Disposal of Reserve Pit Fluids by Subsurface Injection.

On November 20, 2001, LAC 43: XIX, Subpart 5, Section 433 (slurry injection), went into effect, as did the amendments to the commercial facility rules in LAC 43: XIX, Chapter 5. Prior to the effective date of the rule, the DNR OC approved slurry injection jobs as demonstration projects only.

Section 433 provides requirements that govern applications for slurry injection wells. Such rules provide for Area of Review (AOR) options, criteria for injection and confining zones based on geology, and well construction. Moreover, Section 433 contains reporting, operational, logging, testing, and corrective action requirements. The regulatory regime offered in Section 433 may serve as a model for other states that decide to formalize a slurry injection approval program.

Amendments to LAC 43:XIX.Chapter 3 (Section 315 - annular disposal of reserve pit fluids) are in the final stages of the promulgation process. The current Chapter 3 rules are included in Appendix A. Annular disposal of drilling wastes is currently permitted at pressures that exceed the fracture pressure of the receiving formation. In proposed Section 315 amendments, different construction requirements will apply for disposals above the fracture pressure of the receiving formation from those disposals at pressures below the fracture pressure. A fracture gradient of 0.75 psi per foot will be used to determine which set of construction criteria to apply when drilling the well. The testing and construction criteria for wells in which the injection pressure is anticipated to exceed the fracture pressure are much more stringent that those for wells which will inject below the fracture pressure. In addition, according to the UIC Director for the OC, the DNR is in the process of drafting new regulations for disposal of E&P wastes into salt caverns.[16]

[16] Personal communications between C. Wascom and D. Johnson, Louisiana Department of Natural Resources, Office of Conservation, Baton Rouge, Louisiana, and B. Bryson, Argonne National Laboratory, October 16, 2001, March 5, 2002, and miscellaneous other meetings.

Michigan

The Michigan Department of Environmental Quality (DEQ), through the Director and Supervisor of Wells, oversees the regulation of oil and gas activities. The Geological and Land Management Division (GLM) regulates the exploration and development of Michigan's oil, gas, and mineral resources. Twenty-eight GLMD staff in five district offices regulate oil and gas activities. Michigan regulations cover all aspects of oil and gas activities: well, facility, and flow lines. The Class II program is directly administered by EPA Region V under Section 1422 of the SDWA. However, unlike some other states without UIC primacy, the DEQ requires duplicate permitting for the construction and operation of an injection well.

Michigan's State Geologist, who also serves as the Assistant Supervisor of Wells, indicated that questions associated with slurry injection or downhole disposal of drill cuttings had never really surfaced. Thus far, the state has not received any requests from operators. Fracturing of the subsurface formations by injection would not be allowed. All fluids would have to be disposed of at pressure amounts that are lower than the fracture gradient pressure. Unlike other states without UIC primacy (e.g., Kentucky), the Michigan DEQ would not approve injection activities that exceeded the fracture pressure of the formation even if the EPA was in favor of the project.

However, like other states, Michigan can grant administrative approval of slurry injection, annular injection, or subfracture injection if the Assistant Supervisor of Wells believes that USDWs or other environmental resources will not be endangered. Michigan does not allow surface disposal and does assure that surface resources (e.g., occurrence of shallow groundwater or proximity to lakes, estuaries, or other unfavorable geologic settings) are protected. At present, the Michigan portions of the Great Lakes are off-limits with respect to new leasing for the purposes of oil and gas drilling, including directional drilling under a Great Lake.

Michigan has vast bedded salt deposits of the Silurian Age Salina Group underlying the state. These deposits have been extensively solution mined in some areas of the state and have been used for hydrocarbon storage. Thus far, no development or retrofitting of cavities for disposal of oil and gas waste has been requested.[17]

Mississippi

The Mississippi Oil and Gas Board (the Board), an independent agency composed of five appointed members and headed by the Oil and Gas Supervisor, is responsible for oil and gas regulation in Mississippi. The state is treated as a single geographic region for purposes of administering oil and gas activities; however, field inspectors work out of their homes from seven locations in the state. The Board administers the Class II program pursuant to a primacy agreement with EPA Region IV under Section 1425 of the SDWA.

Mississippi does not have specific regulations or policies governing slurry injection or subfracture injection. However, a procedure for approving or denying annular disposal of "produced fluids" has been promulgated under Rule 63 (Underground Injection), Part 12

[17] Personal communication between T. Godbold, Michigan Department of Environmental Quality, Geological Survey Division, Lansing, Michigan, and B. Bryson, Argonne National Laboratory, November 2, 2001.

(Annular Disposal) of the State Oil and Gas Board Statewide Rules and Regulations (Order No. 201-51). Definition (d) of Rule 63 includes drill cuttings and other solid, liquid, or semisolid E&P waste under the term "produced fluids." Part 12 states:

> The Board, may approve annular disposal of produced fluids for a period of not more than one (1) year, after notice and hearing provided that the outermost casing is properly cemented through the lowermost USDW. The applicant shall provide the Board a Radioactive Tracer Survey (accompanied by an interpretation of the survey by the company which performed the test) to prove that the injected fluid is entering the permitted zone and there are no leaks in the casing. The applicant shall furnish the board an economic study of the well and the economic alternative methods of disposal of produced fluids. No permit for annular injection will be granted where a viable economic alternative is found to exist.

Part 16 (Exceptions) authorizes the Board, after notice and hearing, to grant an exception to any construction or operating provision upon proof of good cause. The operator must demonstrate that proceeding under the exception will not endanger USDWs. Part 13 describes the procedures for exempting aquifers for purposes of produced fluid disposal. The exemption cannot go into effect without the concurrence of the Mississippi Board of Health and the Board of Water Resources. Part 16 is similar to oil and gas regulations in most producing states that give the Director or Board the flexibility to approve other methods—on an experimental or a case-by-case basis when a technical subject is not covered in the regulations. Thus, slurry injection or open-hole disposal of drilling waste slurry would have to be approved under Part 16 in Mississippi.

The Mississippi Class II UIC regulations closely follow the UIC regulations used by the EPA. The Mississippi Class II primacy program was not approved until the 1990s, while most of the other states received Class II primacy under Section 1425 of the SDWA in the early to mid-1980s. The annular injection regulation for Mississippi does not mention pressure or volume limitations. It focuses the integrity assessment on the proof the casing is sound and does not leak. Unlike some states that approve annular disposal administratively through the Director or field supervisor, the Mississippi program requires full notice and hearing before the Board. On its face, Rule 12 does allow the disposal of E&P wastes by injection at offshore facilities. However, in light of the proof needed relative to approval of annular disposal, Mississippi apparently considers this method a least favored option for reserve pit closure.

Mississippi stores natural gas and LPG in caverns formed in salt domes. In 1997, the Board received a preliminary request to consider injection of E&P wastes into the cap rock on the flanks of a salt dome. After reviewing information supplied by the applicant, the Board rejected the proposal. No other caverns have been used for E&P waste disposal in Mississippi.[18]

[18] Personal communication between W. Boone, Mississippi State Oil and Gas Board, Jackson, Mississippi, and B. Bryson, Argonne National Laboratory, November 29, 2001.

Missouri

The Missouri Department of Natural Resources' Geological Survey and Resource Assessment Division administers oil and gas regulation in Missouri. Missouri is treated as a single geographical region for the purposes of oil and gas regulation. Where found in Missouri, oil and gas occur in relatively shallow deposits. Approximately 80% of production occurs in the Kansas City area from Pennsylvanian formations of the Forest City Basin at depths between 400 and 600 feet. Approximately 10% of production occurs in extreme Northwestern Missouri. Deepest production is from the Ordovician Kimmswick Limestone at a depth of about 3,000 feet. An additional 10% of production occurs from the Florissant Dome in the St. Louis area. Production is from the Kimmswick Limestone at approximately 1,200 feet below ground surface.

Due to shallow depth of most of Missouri's wells, they are typically air drilled, and thus a minimal amount of cuttings is generated. Deeper wells have the potential to be air drilled using mud rotary. In these cases, drill cuttings are typically buried on site. Applicable regulations do not address disposal of E&P waste by injection. However, plugging regulations do allow mud-laden fluids to be used in conjunction with cement if approval is obtained in advance of plugging from the State Geologist.

Missouri hosts no significant salt deposits. However, at one time, limestone caverns were evaluated for the storage of oil waste. The concept was rejected because good hydrologic evidence suggests that the oil waste would not remain in the cavern. Missouri has received Class II program primacy under Section 1425 of the SDWA.[19]

Montana

The Board of Oil and Gas Conservation (the Board) is an independent agency under the direction of the Administrator. The head office in Billings serves as the main technical office and well data library. One regional office is located in the northern part of the state. Montana has received Class II primacy under Section 1425 of the SDWA from EPA Region VIII. The Administrator indicated that the state would use the UIC program to approve or deny the injection of drill cuttings. Historically, operators used to request permission to inject drilling pit contents down the annulus of a producing well before abandonment. Most of the requests came from the Williston Basin in the Northeast corner of the state where the Williston oil-producing formation extends over into North Dakota. In the mid-1980s, operators abandoned this technology, partly due to economic conditions in 1986, but also because the Board was not wholeheartedly supportive of the practice.

The Board has no statutes, regulations, or written policies that prohibit slurry injection or any other related injection practice for the disposal of drilling pit waste. In theory, an operator could file an application for a special permit. If the Administrator approved the application, the Board would issue a Sundry Notice. If the well were located on federal lands, the Bureau of Land

[19] Personal communication between I. Satterfield, Missouri Dept of Natural Resources, Missouri Geological Survey, Rolla, Missouri, and B. Bryson, Argonne National Laboratory, 2001 (exact date not available).

Management (BLM) would have to issue a permit to the operator. At present, no salt caverns for oil field waste disposal are under development in Montana.[20]

Nebraska

The Nebraska Oil and Gas Conservation Commission (NOGCC) is an independent agency entrusted with the sole statutory authority to regulate the oil and gas industry. Nebraska is treated as a single geographic region for purposes of administering the regulations. Individual inspectors work out of their homes throughout the state. Nebraska has received Class II program primacy under Section 1425 of the SDWA. The NOGCC has indicated that it would use the pertinent portions of its UIC program to approve or deny the injection of drill cuttings slurry. The state has not promulgated any specific regulations governing slurry injection, subfracture injection, annular injection, or disposal into salt caverns.

The Deputy Director for the NOGCC, who also serves as UIC Supervisor, noted that no operator requests for activities related to slurry injection have thus far been received. A request would be approved or denied administratively on a case-by-case basis. The Deputy Director emphasized the absence of a bias against slurry or subfracture injection in Nebraska. However, he noted that these technologies did not provide attractive options to the industry as long as burial of drilling wastes was permitted by the state as an environmentally safe and more economical method. Burial, including managed encapsulation of drilling pit locations, is cheaper than injecting waste slurry.[21]

Nevada

The Nevada Commission of Mineral Resources, Division of Minerals, is responsible for administering the development and production of oil, gas, and geothermal resources. Nevada is treated as a single geographic region for purposes of administering the regulation of oil and gas. Much of the state's land mass and most oil and gas operations fall on federal land. Thus, administration and regulation are jointly conducted with federal agencies, primarily the BLM. According to a Nevada UIC official, no operator has ever requested to use slurry injection. However, some one-time disposal of drilling mud down the annulus of a producing well has occurred on land administered by the BLM. The Class II program is administered by the state pursuant to a primacy agreement with EPA Region IX under Section 1425 of the SDWA. The state has no regulations or policies governing slurry injection or other injection activities related to drilling waste.[22]

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[20] Personal communications between T. Richmond, Montana Board of Oil and Gas Conservation, Billings, Montana, and B. Bryson, Argonne National Laboratory, November 28, 2001, and March 5, 2002.
[21] Personal communications between S. Belieu, Nebraska Oil and Gas Conservation Commission, Sidney, Nebraska, and B. Bryson, Argonne National Laboratory, September 19, 2001, and January 22, 2002.
[22] Personal communication between J. Snow, Nevada Commission of Mineral Resources, Division of Minerals, Carson City, Nevada, and B. Bryson, Argonne, National Laboratory, December 13, 2001.

New Mexico

The Oil Conservation Division (OCD) in the Energy, Minerals, and Natural Resources Department administers all state oil and gas regulations in New Mexico. The four district offices are headed by supervisors who are responsible for monitoring oil and gas field operations and enforcing regulations within their respective districts. The central office in Santa Fe undertakes the permitting for all injection wells. New Mexico administers the Class II program through a primacy agreement with the EPA under Section 1425 of the SDWA.

The UIC Section Chief indicated that, to his knowledge, the OCD had never received any requests from oil or gas operators to apply slurry injection, subfracture injection, or annular injection. New Mexico has no specific regulations governing these practices. Operators have used proper dewatering and closure of pits at drilling locations to dispose of drill cuttings. The UIC Section Chief recalled one formal request for a permit to dispose of cuttings and other oil field waste into a salt cavern. However, the operator was unable to provide adequate engineering and geological justification to the state. The application was subsequently withdrawn. As in most oil- and gas-producing states, the Director of the OCD enjoys broad administrative powers to allow experimental new technologies provided that oil and gas conservation and environmental protection are maintained. Most of these situations are subject to a hearing—after third-party protest or at the agency's own motion.[23]

New York

The primary responsibility for regulating oil and gas activities within New York resides with the Division of Mineral Resources in the New York Department of Environmental Conservation (the DEC). Oil and gas well permitting and most field enforcement for four of the Department's nine regions are conducted out of the Avon and Allegany offices, while the other five regions are administered from Albany.

The Division has never received any requests for slurry injection, subsurface injection, or annular disposal of drilling and reserve-pit wastes. The DEC has never developed regulations, policies or guidelines governing these activities and no plans for promulgating regulations are imminent. At present, no drilling operations are conducted in the offshore areas of New York or in Lake Erie. EPA Region II administers the Class II program for New York under Section 1422 of the SDWA. [24]

North Dakota

The North Dakota Industrial Commission, through its Oil and Gas Division, is the regulatory agency for oil and gas exploration and production activities. North Dakota is treated as a single

[23]Personal communications between L. Wrotenbery and D. Catanach, New Mexico Department of Energy, Minerals, and Natural Resources, Santa Fe, New Mexico, and B. Bryson, Argonne National Laboratory, September 18, 2001, October 16, 2001, and November 27, 2001.
[24] Personal communications between D. Drazan and K. Sanford, New York Department of Environmental Conservation, Division of Mineral Resources, Albany, New York, and B. Bryson, Argonne National Laboratory, March 11, 12, 2002.

geographic region for oil and gas. However, the Division maintains three field offices for inspection and enforcement activities. The Division administers the Class II program under primacy agreement with EPA Region VIII.

North Dakota does not have any rules and regulations governing slurry injection or subfracture injection. However, a policy, dated August 17, 1998, entitled "Policy for Onsite Downhole Disposal of Drilling Fluids," does exist. This policy addresses annular disposal and open-hole disposal.

- Guidelines for true annular disposal (pump down surface-production casing annulus):
  1. Surface casing Cement Bond Log (CBL) - bottom 500 ft minimum, no pressure required.
  2. Temperature log - before and after disposal.
  3. Pressure test surface casing (prior to setting production casing).
  4. Maximum injection pressure = 75% of test pressure.

  Note: If the surface casing pressure test fails, no injection is allowed. Any surface casing leak must be remediated (squeeze, etc.) prior to setting production casing.

- Guidelines for open-hole disposal (no production casing set, pump through drill pipe and retainer set at base of surface casing):

  1. Surface casing CBL - bottom 500 ft minimum, no pressure required.
  2. Temperature log - before and after disposal.
  3. Retainer or packer set at base of surface casing. Pump through drill pipe or tubing.
  4. Pressure test surface casing - drill pipe annulus to 500-psi minimum prior to pumping.
  5. Maximum injection pressure based on 90% of surface casing burst strength and 10.5 lb/gal mud. The injection pressure may be adjusted upward if the mud weight is substantially lighter.
  6. Continuous pressure recorder (injection pressure).

  Note 1: If the surface casing pressure test fails, no injection is allowed. The leak must be isolated, and cement placed across when plugging.

  Note 2: Calculating maximum surface injection pressure (open hole):
  - Maximum surface casing pressure = 0.9 * burst strength
  - Maximum surface injection pressure
    = Maximum casing pressure - Hydrostatic head
    = (0.9 casing burst strength - [(mud weight/8.34) * 0.433 casing depth]

North Dakota uses the burst strength of the surface casing rather than the calculated fracture pressure of the injection zone as a guideline. At shallower depths, fracture pressures could conceivably be reached. Annular injection is allowed for newly completed producing wells in areas where pits are dug into glacial till. The CBL for the bottom 500 ft of the hole is essential to gain approval. Commercial injection wells or dedicated wells for disposal of drilling and reserve pit contents do not currently exist. Operators have not requested using drilling waste as spacers in well plugging. The North Dakota policy applies to one-time disposal of drilling waste in the well of origin. Transfer or transportation of waste from one location to another does not qualify.

North Dakota has no salt deposits that could support cavern development.[25]

Ohio

The Division of Mineral Resources Management (DMRM) in the Ohio Department of Natural Resources (ODNR) regulates all oil and gas drilling, producing, plugging, and oil field waste disposal operations. The ODNR has an administrative office in Columbus and seven district offices located in three regions of the state. Ohio has received Class II program primacy from EPA Region V under Section 1425 of the SDWA. While Ohio does not have regulations or policies pertaining to slurry injection or subfracture injection, rules governing annular disposal have been in place since the USEPA awarded primacy in 1983. Annular disposal of "brine or other wastes substances resulting, obtained or produced in connection with oil and gas drilling exploration or production" is authorized by Section 1509.22(C)(1) of the Ohio Revised Code (ORC) and rules adopted pursuant to 1509.22(d) of the ORC. Rules governing annular disposal are found in Rule 1501:9-3-11 of the Ohio Administrative Code. In practice, annular disposal is used for injection of produced brine rather than fluids generated during drilling operations; however, nothing in the statutes or regulations would prohibit the disposal of drilling wastes through annular injection because all pits, tanks, or sealed catchment basins contain some produced water in the liquid portion of the waste. The Deputy Chief of the DMRM indicated that most operators dewatered pits prior to closure in accordance with the applicable state E&P pit closure regulations. Some drilling wastes may be transported to another lease for land treatment or disposal if the well of origin is located in a populated or environmentally sensitive area. Many of the gas wells are drilled with air rotary tools. However, it does not necessarily mean that they only generate small volumes of E&P wastes.[26]

Oklahoma

The Oklahoma Corporation Commission (OCC), through the Oil and Gas Division, administers the regulation of oil and gas. The OCC has a central office in Oklahoma City and four district offices. Oklahoma was the first state to receive primacy from EPA Region VI for its Class II program under the SDWA in late 1981.

Oklahoma has two administrative regulations that govern approval for one-time injection of reserve pit fluids. The first regulation is found in Title 165 (Corporation Commission), Chapter 10 (Oil And Gas Conservation), Subchapter 5 (Underground Injection Control), Section 12 of the Oklahoma Administrative Code (OAC), entitled Application for Administrative Approval for the Subsurface Injection of Onsite Reserve Pit Fluids (OAC 165:10-5-12). This regulation provides that the subsurface injection of reserve pit fluids is prohibited into (1) a newly drilled well that is

[25] Personal communications between M. Bohrer, North Dakota Industrial Commission, Oil and Gas Division, Bismarck, North Dakota, and B. Bryson, Argonne National Laboratory, November 30, 2001, and January 22, 2002.
[26] Personal communication between S. Kell, Ohio Department of Natural Resources, Division of Mineral Resources Management, Columbus, Ohio, and B. Bryson, Argonne National Laboratory, September 23, 2001.

to be plugged and abandoned, or (2) the casing annulus of a well being drilled, a recently completed well, or a well that has been worked over, unless an application is approved by the Commission pursuant to OAC 165:10-5-13. All applications are approved on a case-by-case basis. The second regulation, OAC 165:10-5-13, provides the following requirements for one-time injection approval.

The general requirements include:

(1) Injection of reserve pit fluids shall be limited to injection of only those fluids generated in the drilling, deepening, or workover of the specific well for which authorization is requested.
(2) An annular injection site shall be inspected by a duly authorized representative of the Commission prior to injection.
(3) The applicant shall file with the Underground Injection Control section an affidavit of delivery or mailing not later than five days after the application is filed.
(4) An operator who disposes of drilling fluid into the surface casing or annulus without approval from the Manager of Pollution Abatement shall be fined $2,500.00.

The criteria for approval include:

(1) Casing string injection may be permitted if the following conditions are met and injection will not endanger treatable water.
    (A) Surface casing injection may be authorized provided the surface casing is set and cemented at least 200 ft below the base of treatable water or,
    (B) Intermediate casing injection may be authorized provided that the surface casing is set at least 200 ft below the treatable water. (In the case of either A or B, the Commission may impose other provisions.)
(2) Injection pressures shall be limited so that vertical fractures will not extend to the base of treatable water.
(3) Each application for annular injection shall be submitted to the UIC Department in quadruplicate on forms prescribed by the Department. An affidavit of mailing a copy of the form to the landowner and to each operator of a producing lease within ½ mile of the subject lease must be attached to one copy of the form. A copy of the CBL must be attached, if run.

A permit is valid for three months and thereafter expires on its own terms. The Manager of the UIC Department may grant emergency authority to inject pit fluids into the annulus, provided that an imminent environmental danger exists. In the absence of a protest by an affected party within 15 days of the date of mailing of the application form 1015T, the application shall be submitted for administrative approval. If a protest is received within the protest period, the operator shall, within 30 days, set and give proper notice of a date of hearing on the Pollution Docket before an Administrative Law Judge.

The Oklahoma program offers operators the opportunity to apply slurry injection technology. However, unless an exception is sought, the state would restrict slurry injection of drilling waste to the annulus of the producing well of origin. While Oklahoma hosts commercial disposal wells, it does not have dedicated wells for drilling waste disposal.

Oklahoma is underlain by bedded salt in some of the state, but no caverns are used for E&P waste disposal.[27]

Pennsylvania

The State of Pennsylvania regulates oil and gas activities through the Department of Environmental Protection, Bureau of Oil and Gas Management. EPA Region III directly administers the Class II program under Section 1422 of the SDWA. (For a description of EPA's position with respect to subfracture injection of oil and gas drilling waste, see Kentucky.) The Senior Technical Specialist of EPA Region III indicated that in light of the number of air-drilled wells in Pennsylvania, slurry injection and other associated injection technologies were not practical. A state technical program supervisor added that, in the past, some drilling waste had been used for spacers during the plugging and abandonment of a well. No salt caverns or coal mines have been used for disposal of drilling waste. EPA staff indicated that geologic formations in Pennsylvania are very tight, with very little formation storage availability (e.g., low permeability and porosity). Unless prohibited by the state, annular disposal of drill cuttings would be permitted by the EPA on a one-time disposal basis, between the long string casing and borehole (below USDWs), and below fracture pressure.[28]

South Dakota

Oil and gas regulations in South Dakota are administered by the Department of Environment and Natural Resources (DENR), Board of Minerals and Environment. South Dakota received UIC program primacy in 1984. South Dakota is a single administrative geographic region for oil and gas regulation. No district offices exist.

In South Dakota, no specific regulation addresses slurry fracture injection, sub-fracture injection or annular injection. The Supervisor of the Oil and Gas Program indicated that the state had not received any requests for slurry injection, subfracture injection, annular disposal, or disposal of drilling wastes into salt caverns. Any application for slurry disposal in South Dakota could be handled administratively. When it does happen, the application will be carefully reviewed by the DENR (and the USEPA if an aquifer exemption becomes involved). If no protests or interventions are made after notice and hearing, the DENR can issue the permit. If intervention is filed, the matter will be scheduled for hearing before the Board of Minerals and Environment. Disposal of drilling pit contents down the annulus of a producing well would, in all likelihood, receive a negative recommendation from staff upon referral of the matter to the Board.

[27] Personal communications between L. Fiddler and T. Baker, Oklahoma Corporation Commission, Oil and Gas Conservation Division, Oklahoma City, Oklahoma; and B. Bryson, Argonne National Laboratory, September 23, 2001, November 27, 2001, and December 3, 2001.
[28] Personal communications among R. Gilius, Department of Environmental Protection, Bureau of Oil and Gas Management, Harrisburg, Pennsylvania, S. Platt, EPA Region III, Philadelphia, Pennsylvania, and B. Bryson, Argonne National Laboratory, December 11, 2001, and March 5, 2002.

South Dakota has salt deposits in the northwest corner counties of the state, but they have not been developed for storage or other purposes. The Supervisor indicated that this might be because of the inadequate thickness and purity of the salt.[29]

Tennessee

All regulation of oil and gas in Tennessee, except for the rules governing UIC, is administered through the State Oil and Gas Board in the Bureau of Conservation, Department of Environment and Conservation. Tennessee is treated as a single geographic administrative region for oil and gas regulation. EPA Region IV administers the Class II program through DI under Section 1422 of the SDWA.

Tennessee has no specific statutes, regulations, or policies governing slurry injection, sub-fracture injection, or annular injection of drill cuttings. The Board does not issue duplicate UIC permits. Historically, the EPA has allowed at least one operator to dispose of drilling waste down the annulus of a producing well on a one-time basis in neighboring Kentucky. In that case, the EPA required that the injection pressure did not exceed the pressure furnished naturally by the hydrostatic head. The Board, like most sister state agencies, enjoys rather broad administrative approval powers with respect to new technologies. In the case of Tennessee, however, the state defers to the EPA relative to permits for subsurface injection of drilling waste.[30]

Texas

The Railroad Commission of Texas (TRC), Oil and Gas Division, is responsible for administering all oil and gas regulatory activities, except for oil and gas leasing, royalty payments, surface damages through oil and gas operations, and contractual matters between operators and landowners. The Oil and Gas Division operates nine district offices, each staffed with field enforcement and support personnel. The Legal Division provides support with respect to the interpretation of rules and regulations as well as enforcement response.

The Oil and Gas Division regulates injection into productive formations and disposal of oil and gas wastes into nonproductive formations. The Division also regulates the solution mining of salt and hydrocarbon storage into salt caverns and depleted oil and gas reservoirs (porosity storage). The TRC has received Class II program primacy from EPA Region VI under Section 1425 of the SDWA. Class III program primacy for solution mining wells pursuant to Section 1422 of SDWA is pending EPA approval.

Over the years, the TRC has permitted subfracture injection and annular injection of reserve pit wastes and other oil field-related wastes. Drill cutting wastes and spent drilling mud may also be injected into a dry and abandoned well prior to plugging, provided that the activity will not sacrifice the integrity of the plugs when established at critical depths in the hole. Texas does not

[29] Personal communication between F. Steece, South Dakota Department of Environmental and Natural Resources, Oil and Gas Program, Rapid City, South Dakota, and B. Bryson, Argonne National Laboratory, March 5, 2002.
[30] Personal communication between S. Platt, Region III, U.S. Environmental Protection Agency, Philadelphia, Pennsylvania, and B. Bryson, Argonne National Laboratory, March 5, 2002.

have specific rules governing the disposal of drilling wastes by annular injection into wells but has a permit policy and a draft rule for injection into salt caverns.

The TRC uses four sets of Statewide Rules from Title 16 (Economic Regulation), Part 1 (Railroad Commission of Texas), Chapter 3 (Oil and Gas Division) of the Texas Administrative Code (TAC) to regulate the disposal of oil and gas wastes, including produced water: (1) Rule §3.8 (Water Protection); (2) Rule §3.9 (Disposal Wells); (3) Rule §3.14 (Plugging); and (4) Rule §3.46 (Fluid Injection).

The definition of oil and gas wastes under Subsection (a) (26) of Statewide Rule 8 is central to the TRC's regulatory management of drilling waste disposal:

> Materials to be disposed of or reclaimed which have been generated in connection with activities associated with the exploration, development, and production of oil or gas or geothermal resources, as those activities are defined in paragraph (30) of this subsection, and materials to be disposed of or reclaimed which have been generated in connection with activities associated with the solution mining of brine. The term "oil and gas wastes" includes, but is not limited to, saltwater, other mineralized water, sludge, spent drilling fluids, cuttings, waste oil, spent completion fluids, and other liquid, semiliquid, or solid waste material. (The rest of the definition lists eligible sources, including gas-processing plants, but designates as ineligible federal hazardous wastes under RCRA.)

Subsection (a) (30) of Statewide Rule 8 specifies the activities that are considered to be associated with the exploration, development and production of oil, gas, and geothermal resources. It includes underground hydrocarbon storage facilities.

The salient features of the extensive regulatory framework in Texas include the following:

(1) Statewide Rule 8 (Water Protection) allows operators to dispose of drilling waste down the annulus of a producing well or down the well bore of dry and abandoned well prior to plugging without a permit so long as the wastes were generated at that specific well site. The TRC may require tests to monitor the quality of the water that is disposed of and has pressure limitations and other measures to ensure that the waste is disposed of into intended target formations.

(2) Statewide Rule 9 (Disposal Wells) governs the permitting, operating, monitoring, and testing of disposal wells. All disposal wells require permits from the TRC. This includes commercial disposal wells, which are defined in Subsection (4) of Rule §3.9:

> For the purposes of this rule, "commercial disposal well" means a well whose owner or operator receives compensation from others for the disposal of oil field fluids or oil and gas wastes that are wholly or partially trucked or hauled to the well, and the primary business purpose for the well is to provide these services for compensation.

(3) Statewide Rule 14 (Plugging) conceivably allows operators to use drilling fluids and muds as spacers between plugs in an abandoned well during the plugging procedures for abandonment, provided the fluid meets certain weight and viscosity requirements.

Texas is the only state to have permitted salt caverns for E&P waste disposal. As of August 2002, 11 caverns have been permitted at 7 locations. All of these caverns may receive E&P wastes, including drilling wastes, and three of them may also receive NORM. Most of these are located in western Texas to serve the Permian Basin oil fields but the most recently permitted cavern, however, is located on the Moss Bluff Salt Dome between Houston and Beaumont and began receiving primarily offshore waste in August of 2000. The TRC permit mandates the sampling and testing of all waste to ensure that it is nonhazardous. The cavern depth below surface ranges from 1,410 ft (roof location) to 1,975 ft (floor location). It offers a disposal volume of 6.2 million barrels. The pumping pressures from the receiving basins to the cavern head are minimal, averaging less than 250 psig at the wellhead. Pressures in the brine line are zero or negative (on gravity). As of January 2002, the cavern has received about one million barrels.[31]

Utah

The Division of Oil, Gas, and Mining (the Division) in the Utah Department of Natural Resources administers oil and gas regulation in Utah. Utah is treated as a single administrative region in the context of oil and gas regulation. Utah has received Class II program primacy from the EPA under Section 1425 of the SDWA. EPA retains Class II regulatory jurisdiction for Indian lands within Utah that include the Uintah-Ouray lands in northeastern Utah and the Navajo Nation lands in southeastern Utah.

The Associate Director of the Division indicated that, to his knowledge, no operator had ever requested to use slurry fracture injection or sub-fracture injection to dispose of drill cuttings in a well; however several cases of reserve pit drilling fluid disposal have been allowed under the rule cited below. Utah is an arid state. Most drilling mud and drill cuttings are allowed to dry prior to burial in pits and closure and encapsulation. Occasionally, an operator will request permission from Division staff to haul E&P waste from one pit location to another lease based on environmental considerations. Any operator request for slurry fracture injection, sub-fracture injection, and annular injection would be decided administratively on a case-by-case basis.

Utah's oil and gas regulatory program does have a rule, Utah Admin. Code R649-3, Underground Disposal of Drilling Fluids that allows injection of reserve pit drilling fluids generally by annular disposal upon completion of drilling. The rule requires the Division to apply the same technical evaluative standards as for a disposal well approval that would likely include a requirement to limit injection pressures to fracture parting pressure. As the rule states, such approvals for disposal are considered on a case-by-case basis. No Utah salt deposits have been development for waste disposal.[32]

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[31]Personal communications between R. Ginn, Texas Railroad Commission Oil and Gas Division, Austin, Texas, and B. Bryson, Argonne National Laboratory, September 18, 2001, and March 5, 2002.
[32] Personal communication between J. Baza, Utah Department of Natural Resources, Division of Oil, Gas and Mining, Salt Lake City, Utah, and B. Bryson, Argonne National Laboratory, November 30, 2001.

Virginia

The Virginia Division of Oil and Gas is a branch of the Department of Mines, Minerals, and Energy. Virginia is treated as a single geographic region for the administration of oil and gas regulation. The Division of Oil and Gas is located at Abingdon in the western part of Virginia, where most of the state's oil and gas are produced. Virginia is primarily a gas-producing state. EPA Region IV directly administers the Class II program under Section 1422 of the SDWA. (For a discussion of the EPA's posture with respect to slurry injection and related practices, see Kentucky.)

Most of the wells in Virginia are drilled by air, and thus the amounts of cuttings are small. Virginia has no statutes, regulations or policies governing slurry, subfracture injection, or annular disposal of drill cuttings. Operator requests would be handled administratively on a case-by-case basis. In the western part of the state, the regulations offer flexibility for using alternative methods of plugging wells. This could include the use of drill cuttings as a part of the spacers. Plugging regulations do not offer this avenue in the Coastal Plain of the state because at one time in the past, drilling mud entered the pond at a fish hatchery from a breakout of drilling mud used in the plugging of a well. Drilling muds are usually hauled out of state to Texas. Virginia does not allow disposal of drill cuttings into salt deposits (or coal beds). The EPA has approved the use of deep coal mines in Virginia for the disposal of drilling pit contents.[33]

West Virginia

The Office of Oil and Gas (OOG) is part of the Division of Environmental Protection in the Department of Commerce, Labor, and Environmental Resources. The OOG regulates oil and gas, while its parent division is also responsible for administering environmental protection regulations, including water resources. Operators have never requested permission to use slurry injection or subfracture injection technologies for disposing of oil field drilling waste in West Virginia. Similarly, requests for one-time disposal of drill cuttings down the annulus have thus far not been submitted to the OOG.

Currently, no regulations are in place that govern the injection of any fluids or materials, except for produced water, which is covered under the Class II program. West Virginia has received Class II program primacy from the EPA under Section 1425 of the SDWA. The spokesperson for West Virginia indicated that a large number of wells are air drilled. The small amounts of waste and cuttings generated at a given well location are disposed of into pits and subsequently buried in an environmentally sound manner. The Office has not seen any need to promulgate specific regulations or develop policy in light of the lack of interest in slurry injection. A one-

[33] Personal communication between B. Wilson, Virginia Department of Mines, Minerals and Energy, Division of Oil and Gas, Abingdon, Virginia, and B. Bryson, Argonne National Laboratory, December 13, 2001, and December 19, 2001.

time request for slurry injection or other related technologies would be resolved administratively under the UIC program.[34]

Wyoming

The Wyoming Oil and Gas Conservation Commission (WOGCC) is a state agency authorized to regulate nonhazardous waste and all aspects of oil and gas E&P on fee patented and state leases. The WOGCC administers the federal lease UIC program for Class II wells on all lands except the Wind River Indian Reservation (on nonfederal) lands. The Wyoming Department of Environmental Quality regulates all forms of commercial subsurface injection and E&P operations that generate or handle hazardous waste. The injection wells on the Wind River Indian Reservation are directly regulated by EPA Region VIII. The Commission administers a single geographic region. It does not have district or regional offices that carry out some of the administrative or technical tasks. In Wyoming, the operator may apply to the Commission for the one-time disposal of a "limited volume" of fluid produced in the course of drilling operations from one specific well. Disposal by injection cannot be initiated until the Commission has granted approval. The regulation is well-specific and not designed for downhole disposal of drilling fluids from offsetting or additional wells on the same lease or from other leases. One-time disposal may occur down the annulus of a newly completed producing well and into a subsurface formation with TDS content in excess of 10,000 mg/L. Moreover, reserve pit fluids may be disposed of on a one-time basis into a dry-hole well prior to plugging.

The rules governing slurry or injected drilling pit fluids are contained in Chapter 4 (Environmental Rules [Underground Injection Control Program -- Enhanced Recovery]), Section 1 (Pollution and Surface Damage [Forms 14A and 14B]), Subsections (tt) through (ww) of the Wyoming Rules and Regulations. During the application of slurry injection, the pump pressure must be limited so that fractures will not extend to the base of a USDW or a groundwater aquifer. As a part of the application, the operator has to show the completion program for the well, the formation tops and the depth of the lowest USDW, the analyses of the fluid to be injected, and the estimated disposal volumes. The operator is also required to notify the Commission 24 hours prior to the disposal operation and give it the opportunity to witness the event. The Wyoming regulations make no distinction between slurry injection and subfracture injection because the pressure is controlled through the calculated maximum fracture pressure and the volume. Chapter 4 also establishes an aquifer exemption process that an operator may invoke in lieu of the 10,000 mg/L TDS limitation.

Wyoming believes that the state program is stricter than others with respect to allowing slurry injection, because the injection is limited to a single well location. A centralized facility or dedicated well would, in all likelihood, not be approved although the agency enjoys broad administrative authority to approve exceptions for just cause.[35]

[34] Personal communication between M. Lewis, West Virginia Department of Commerce, Labor and Environmental Resources, Office of Oil and Gas, Charleston, West Virginia, and B. Bryson, Argonne National Laboratory, September 21, 2001.
[35] Personal communications between C. Eggerman, Wyoming Oil and Gas Conservation Commission, Casper, Wyoming, and B. Bryson, Argonne National Laboratory, March 5, 2002, and March 11, 2002.

Chapter 5 – Requirements for Injection of Drilling Wastes on Federal Lands

Two agencies within the U.S. Department of the Interior have extensive jurisdiction over oil and gas activities located on federal lands. The BLM administers oil and gas programs on vast areas of onshore federal land, while the Minerals Management Service (MMS) has responsibility for offshore oil and gas leasing and activities in federal waters. The regulatory requirements used by these agencies are discussed below.

Bureau of Land Management

At the start of this project, the authors contacted management at MMS headquarters to learn if BLM had any experience with slurry injection or other forms of solids injection. The BLM circulated the request to multiple field offices. The only office that responded was the Eastern States office that has jurisdiction over the eastern half of the United States. The person providing information indicated that for oil and gas development administered through that office, applicants needed to file an Application for Permit to Drill on federal mineral estate. As part of the Application for Permit, the company would need to state how they intended to dispose of its drilling and production wastes. As long as the method is one that would be approved by EPA or the state in which the federal lands are located (when the state has primacy), the BLM office would not get involved any further with the waste management. The contact noted that other BLM offices in western states did not necessarily follow the same. This could not be confirmed because the other BLM offices did not reply to our inquiry.[36]

Minerals Management Service

In U.S. offshore areas, companies may inject E&P wastes that originate on the Outer Continental Shelf into injection wells or encapsulate them in the well bore of wells that are about to be abandoned. Each application for underground waste disposal must be authorized on a case-by-case basis by the MMS. The MMS requirements for underground injection of wastes are contained in a Notice to Lessees document, NTL No. 99-G22, Guidelines for the Sub-Seabed Disposal and Offshore Storage of Solid Wastes. The NTL No. 99-G22 requirements are described below.

If companies inject wastes through underground injection wells, the formation receiving the wastes must be located below the deepest drinking water aquifer, must be isolated above and below by shale layers, and may not contain any producing wells. Companies must demonstrate that injection wells have mechanical integrity (they do not leak fluids into formations other than those that are intended to receive the fluids).

Companies may also use two different types of encapsulation. In the first type, wastes are placed directly in the well bore of a well that is being abandoned. In the second type, wastes are placed into a section of pipe, caps are put on both ends, and the pipe section is lowered into the well bore. In either case, the wells selected to receive the wastes must not be intersected by faults that extend upward to the sea floor and must not be located in an area with mud flows, slumps,

[36] Personal communication between D. LaChance, BLM Eastern States Office, Milwaukee, Wisconsin, and J. Veil, Argonne National Laboratory, July 26, 2001.

or slides. The top of the encapsulated waste must be located at least 1,000 ft below the sea floor. A cement plug of at least 200 ft must be placed above and below the encapsulated waste.

Chapter 6 – Acknowledgments

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Table 1 - Summary of State Regulatory Programs for Injection of E&P Wastes

State	**State UIC Primacy (SP) or EPA Direct Implementation (DI)**	**Technology Type[a]** **Slurry Injection (SI), Subfracture Injection (SFI), Annular Injection (AI), Plugging and Abandonment (P&A), Salt Cavern Disposal (SCD), Coal Mine (CM)** **Request Status: No Requests (NR)**	**Regulatory Practice[b]** **General Regulation (GR) or Specific Regulation (SR) or Policy (P)** **Experimental Practice Permit (SREP)** **Waste from Well of Origin Only (WO)** **Waste from Multiple Wells (M)**	**Citation Or Guidance**	**Agency Responsible for Implementation**
Alabama	SP	SI SFI AI	GR (WO) GR (WO) GR (WO)	Class II, Section 1425 AAC Article 6	Alabama Oil and Gas Board
Alaska	SP	SI SFI AI[c] P&A	SR (M) SR (M) SR (M)[d] SR (WO)	20 AAC 25.252[e] 20 AAC 25.252[e] 20 AAC 25.080 20 AAC 25.080	Alaska Oil and Gas Conservation Commission
Arkansas	SP	SFI AI	GR GR	Class II, Section 1425	Arkansas Oil and Gas Commission

State	State UIC Primacy (SP) or EPA Direct Implementation (DI)	Technology Type[a] Slurry Injection (SI), Subfracture Injection (SFI), Annular Injection (AI), Plugging and Abandonment (P&A), Salt Cavern Disposal (SCD), Coal Mine (CM) Request Status: No Requests (NR)	Regulatory Practice[b] General Regulation (GR) or Specific Regulation (SR) or Policy (P) Experimental Practice Permit (SREP) Waste from Well of Origin Only (WO) Waste from Multiple Wells (M)	Citation Or Guidance	Agency Responsible for Implementation
California	SP	SI SFI	GR SREP	Section 1722(k) of Article 3	Department of Conservation — Division of Oil, Gas, and Geothermal Resources
Colorado	SP	NR	None	Class II, Section 1425	Colorado Oil and Gas Commission
Florida	DI	SFI AI	None None	Class II, Section 1422	EPA and Florida Geological Survey
Illinois	SP	SFI AI P&A	GR (WO) GR (WO) GR (WO)	Class II, Section 1425	Illinois Department of Natural Resources
Indiana	SP	P&A	P	Class II, Section 1425	Indiana Department of Natural Resources — Division of Oil and Gas

State	State UIC Primacy (SP) or EPA Direct Implementation (DI)	Technology Type[a] Slurry Injection (SI), Subfracture Injection (SFI), Annular Injection (AI), Plugging and Abandonment (P&A), Salt Cavern Disposal (SCD), Coal Mine (CM) Request Status: No Requests (NR)	Regulatory Practice[b] General Regulation (GR) or Specific Regulation (SR) or Policy (P) Experimental Practice Permit (SREP) Waste from Well of Origin Only (WO) Waste from Multiple Wells (M)	Citation Or Guidance	Agency Responsible for Implementation
Kansas	SP	AI	GR	K.A.R. 82-3-400	Kansas Corporation Commission — Conservation Division
Kentucky	DI	SFI AI	GR GR	Class II, Section 1422 Class II, Section 1422	EPA and Kentucky Department of Mines and Minerals
Louisiana	SP	SI SFI AI SCD	SR SR Regulation amendment pending New Regulation in draft	Statewide Order No. 29-B (LAC 43: XIX, Subpart 1, Chapters 3-5 (especially new Section 433 in Chapter 4)	Louisiana Department of Natural Resources — Office of Conservation

State	State UIC Primacy (SP) or EPA Direct Implementation (DI)	Technology Type[a] Slurry Injection (SI), Subfracture Injection (SFI), Annular Injection (AI), Plugging and Abandonment (P&A), Salt Cavern Disposal (SCD), Coal Mine (CM) Request Status: No Requests (NR)	Regulatory Practice[b] General Regulation (GR) or Specific Regulation (SR) or Policy (P) Experimental Practice Permit (SREP) Waste from Well of Origin Only (WO) Waste from Multiple Wells (M)	Citation Or Guidance	Agency Responsible for Implementation
Michigan	DI/plus state permit	SFI, AI, SCD NR	GR	Class II, Section 1422 Part 615, Supervisor of Wells, Act 451, PA 1994 as amended, Rules 324.703, 324.704, 324.801, 324.802, 324.804	EPA and Michigan Department of Environmental Quality
Mississippi	SP	AI	SR (WO)	Part 12 of Rule 63	Mississippi Oil and Gas Board
Missouri	SP	P&A	GR	10 CSR 50-2.060(3)	Missouri Department of Natural Resources
Montana	SP	NR since 1980s	None	Class II, Section 1425	Montana Board of Oil and Gas Conservation
Nebraska	SP	NR	None	Class II, Section 1425	Nebraska Oil and Gas Commission

State	State UIC Primacy (SP) or EPA Direct Implementation (DI)	Technology Type[a] Slurry Injection (SI), Subfracture Injection (SFI), Annular Injection (AI), Plugging and Abandonment (P&A), Salt Cavern Disposal (SCD), Coal Mine (CM) Request Status: No Requests (NR)	Regulatory Practice[b] General Regulation (GR) or Specific Regulation (SR) or Policy (P) Experimental Practice Permit (SREP) Waste from Well of Origin Only (WO) Waste from Multiple Wells (M)	Citation Or Guidance	Agency Responsible for Implementation
Nevada	SP	NR AI (BLM land)	None GR	Class II, Section 1425	Nevada Commission of Mineral Resources Bureau of Land Management
New Mexico	SP	NR SCD	None One request withdrawn	Class II, Section 1425	New Mexico Department of Energy, Minerals and Natural Resources — Oil Conservation Division
New York	DI	NR	None	Class II, Section 1422	EPA and New York Department of Environmental Conservation — Division of Mineral Resources

State	State UIC Primacy (SP) or EPA Direct Implementation (DI)	Technology Type[a] Slurry Injection (SI), Subfracture Injection (SFI), Annular Injection (AI), Plugging and Abandonment (P&A), Salt Cavern Disposal (SCD), Coal Mine (CM) Request Status: No Requests (NR)	Regulatory Practice[b] General Regulation (GR) or Specific Regulation (SR) or Policy (P) Experimental Practice Permit (SREP) Waste from Well of Origin Only (WO) Waste from Multiple Wells (M)	Citation Or Guidance	Agency Responsible for Implementation
North Dakota	SP	SI SFI AI P&A (NR)	P (WO) P (WO) P (WO) P (WO)	Policy for Onsite Downhole Disposal of Drilling Fluids (August 17, 1998)	North Dakota Industrial Commission — Oil and Gas Division
Ohio	SP	SFI AI NR	None GR	ORC Section 1501 & OAC Section 1501:9	Ohio Department of Natural Resources
Oklahoma	SP	SI SFI AI	SR (WO) SR (WO) SR (WO)	OAC 165:10-5-13	Oklahoma Corporation Commission — Oil and Gas Division
Pennsylvania	DI	SFI AI	GR GR	Class II, Section 1422	EPA and Pennsylvania Department of Environmental Protection

State	State UIC Primacy (SP) or EPA Direct Implementation (DI)	Technology Type[a] Slurry Injection (SI), Subfracture Injection (SFI), Annular Injection (AI), Plugging and Abandonment (P&A), Salt Cavern Disposal (SCD), Coal Mine (CM) Request Status: No Requests (NR)	Regulatory Practice[b] General Regulation (GR) or Specific Regulation (SR) or Policy (P) Experimental Practice Permit (SREP) Waste from Well of Origin Only (WO) Waste from Multiple Wells (M)	Citation Or Guidance	Agency Responsible for Implementation
South Dakota	DI/plus state permit	NR AI	None Never approved	Class II, Section 1422	South Dakota Department of Environment and Natural Resources Board of Minerals and Environment
Tennessee	DI	SFI AI	GR GR	Class II, Section 1422	EPA and State Oil and Gas Board
Texas	SP	SI SFI AI SCD	None P (WO) P (WO) SR (M)	Title 16, Part 1, Chapter 3 (Rules 8, 9, 14, and)	Texas Railroad Commission — Oil and Gas Division

State	State UIC Primacy (SP) or EPA Direct Implementation (DI)	Technology Type[a] Slurry Injection (SI), Subfracture Injection (SFI), Annular Injection (AI), Plugging and Abandonment (P&A), Salt Cavern Disposal (SCD), Coal Mine (CM) Request Status: No Requests (NR)	Regulatory Practice[b] General Regulation (GR) or Specific Regulation (SR) or Policy (P) Experimental Practice Permit (SREP) Waste from Well of Origin Only (WO) Waste from Multiple Wells (M)	Citation Or Guidance	Agency Responsible for Implementation
Utah	SP	SI, AI	SR	Class II, Section 1425 UAC R649-3-25	Utah Department of Natural Resources — Division of Oil, Gas and Mining
Virginia	DI	NR CM	None P (M)	Class II, Section 1422	EPA and Virginia Department of Mines, Minerals, and Energy, Energy Division
West Virginia	SP	NR	None	Class II, Section 1425	West Virginia Division of Environmental Protection, Office of Oil and Gas
Wyoming	SP	SI SFI AI	SR (WO) SR (WO) SR (WO)	Wyoming Oil and Gas Regulations, Chapter 4, Section 1, Subsections (tt) through (vv) Chapter 4, Section 12	Wyoming Oil and Gas Conservation Commission

NOTES:

[a] Column 3 shows approved technologies in use; otherwise, NR (No Request) has been entered.

[b] Column 4 distinguishes between general regulations (GR) and specific regulations (SR). GR refers to UIC authority in general and SR refers to tailored SI, SFI, AI, P&A rules. Most of the states listed have general authority to allow SI, SFI, AI, or spacers in the P&A operations. None means that no regulations exist for SI, SFI, or AI, and general regulations probably do not address subject. WO means approval limited to the Well of Origin; M denotes wastes can be received from more than one well.

[c] Alaska: Alaska regulates annular disposal separately from UIC disposal.

[d] Alaska: The Alaska Oil and Gas Conservation Commission (AOGCC) allows fluids from multiple wells on the same platform or drilling pad to be injected into a single well annulus subject to specific time and volume constraints.

[e] Alaska: UIC disposal (Class II-D) is also covered by specific rules in Injection Orders issued by the Alaska Oil and Gas Conservation Commission (AOGCC).

Appendix A – State Regulations and Other Requirements

This appendix contains the most current text of state regulations available as of October 2002. The material is reproduced here as it appears in the state regulations. It has been formatted cautiously but has not been edited for clarity, grammar, or punctuation. This information is provided solely as reference material. The authors caution readers that regulations change from time to time both in text and organizational numbering. The information in this appendix should not be used for legal proceedings or decision-making. We recommend that readers consult with the appropriate agencies for authorized up-to-date copies of state regulations and requirements.

ALABAMA

Administrative approval process relative to annular injection and plugging.

Use of guidelines rather than regulations.

ALASKA

Alaska Administrative Code (AAC)

Title 20 (Miscellaneous Boards and Commissions), Chapter 25 (Alaska Oil and Gas Conservation Commission)

20 AAC 25.252. Underground Disposal of Oil Field Wastes and Underground Storage of Hydrocarbons

(a) The underground disposal of oil field wastes and the underground storage of hydrocarbons are prohibited except as ordered by the commission under this section. In response to a letter of application for injection filed by an operator, the commission will issue an order authorizing the underground disposal of oil field wastes that the Commission determines are suitable for disposal in a Class II well, as defined in 40 C.F.R. 144.6(b) as revised as of July 1, 1998, which is adopted by reference, or the underground storage of hydrocarbons. An order authorizing disposal or storage wells remains valid unless revoked by the commission.

(b) The operator has the burden of demonstrating that the proposed disposal or storage operation will not allow the movement of oil field wastes or hydrocarbons into sources of freshwater. Disposal or storage wells must be cased and the casing cemented in a manner that will isolate the disposal or storage zone and protect oil, gas, and freshwater sources.

(c) An application for underground disposal or storage must include

(1) a plat showing the location of all proposed disposal and storage wells, abandoned or other unused wells, production wells, dry holes, and any other wells within one-quarter mile of each proposed disposal or storage well;

(2) a list of all operators and surface owners within a one-quarter mile radius of each proposed disposal or storage well;

(3) an affidavit showing that the operators and surface owners within a one-quarter mile radius have been provided a copy of the application for disposal or storage;

(4) the name, description, depth, and thickness of the formation into which fluids are to be disposed or stored and appropriate geological data on the disposal or storage zone and confining zones, including lithologic descriptions and geologic names;

(5) logs of the disposal or storage wells, if not already on file, or other similar information;

(6) a description of the proposed method for demonstrating the mechanical integrity of the casing and tubing under 20 AAC 25.412 and for demonstrating that fluids

will not move behind casing beyond the approved disposal or storage zone, and a description of

(A) the casing of the disposal or storage wells, if the wells are existing; or

(B) the proposed casing program, if the disposal or storage wells are new;

(7) a statement as to the type of oil field wastes to be disposed or hydrocarbons stored, their composition, their source, the estimated maximum amounts to be disposed or stored daily, and the compatibility of fluids to be disposed or stored with the disposal or storage zone;

(8) the estimated average and maximum injection pressure;

(9) evidence to support a commission finding that the proposed disposal or storage operation will not initiate or propagate fractures through the confining zones that might enable the oil field wastes or stored hydrocarbons to enter freshwater strata;

(10) a standard laboratory water analysis, or the results of another method acceptable to the commission, to determine the quality of the water within the formation into which disposal or storage is proposed;

(11) a reference to any applicable freshwater exemption issued in accordance with 20 AAC 25.440; and

(12) a report on the mechanical condition of each well that has penetrated the disposal or storage zone within a one-quarter mile radius of a disposal or storage well.

(d) The mechanical integrity of a disposal or storage well must be demonstrated under 20 AAC 25.412 before disposal or storage operations are begun, after a well workover affecting mechanical integrity is conducted, and at least once every four years. To confirm continued mechanical integrity, the operator shall monitor the injection pressure and rate and the pressure in the casing-tubing annulus during actual disposal or storage operations. The monitored data must be reported monthly on the Monthly Injection Report (Form 10-406).

(e) If an injection rate, operating pressure observation, or pressure test indicates pressure communication or leakage in any casing, tubing, or packer, the operator shall notify the commission by the next working day and shall implement corrective action or increased surveillance as the commission requires to ensure protection of freshwater.

(f) The commission will require additional mechanical integrity tests if the commission considers them prudent for conservation purposes or protection of freshwater.

(g) Modifications of existing or pending disposal or storage operations will be approved by the commission, in its discretion, under 20 AAC 25.507, upon application containing sufficient detail to evaluate the proposed modification. No modification will be approved unless the applicant proves to the commission that the modification will not allow the movement of fluids into sources of freshwater.

(h) If wells, including freshwater wells or other borings, are located within a one-quarter mile radius of the disposal or storage well, are a possible means for oil field wastes or hydrocarbons to move into sources of freshwater, and are under the control of

(1) the operator, the operator shall ensure that the wells are properly repaired, plugged, or otherwise modified to prevent the movement of oil field wastes or hydrocarbons into sources of freshwater; or

(2) a person other than the operator, the commission will not issue an order under (a) of this section to the operator until the operator presents evidence to the commission's satisfaction that the person who controls the wells has properly repaired, plugged, or otherwise modified the wells to prevent the movement of oil field wastes or hydrocarbons into sources of freshwater.

(i) The commission will publish notice of the disposal or storage application and will provide opportunity for a hearing in accordance with 20 AAC 25.540.

(j) If disposal or storage operations are not begun within 24 months after the approval date, the injection approval will expire unless an application for extension is approved by the commission.

(k) The annular disposal of drilling wastes approved under 20 AAC 25.080 is an operation incidental to drilling a well and is not a disposal operation subject to this section.

(l) This section does not apply to underground disposal that is regulated under 40 C.F.R. 147.101 by the United States Environmental Protection Agency.

* * *

20 AAC 25.080. Annular Disposal of Drilling Waste

(a) A person may not dispose of drilling waste through the annular space of a well unless authorized by the commission under this section. The operator of a well permitted under AS 31.05.090 may request authorization for the disposal of drilling waste through the well's annular space by filing with the commission an Application for Sundry Approvals (Form 10-403) supplemented with additional information as required under this section.

(b) A request for authorization under this section must include the following information or refer to that information if that information is already on file with the commission:

(1) the annulus to be used for disposal;

(2) the depth to the base of freshwater aquifers and permafrost, if present;

(3) stratigraphic description of the interval exposed to the open annulus and other information sufficient to support a commission finding that the waste will be confined and will not come to the surface or, except to the extent allowed under (e)(1) of this section, contaminate freshwater;

(4) a list of all publicly recorded wells within one-quarter mile, and all publicly recorded water wells within one mile, of the well that will receive drilling waste;

(5) the types and maximum volume of waste to be disposed of and the estimated density of the waste slurry;

(6) a description of any waste sought to be determined as drilling waste under (h)(3) of this section;

(7) an estimate of the maximum anticipated pressure at the outer casing shoe during disposal operations and calculations showing how this value was determined;

(8) details that show that the shoe of the outer casing is set below the base of permafrost, if present, and any freshwater aquifer, other than freshwater excepted under (e)(1) of this section, and is adequately cemented to provide zone isolation; the information relied upon and submitted must include

(A) cementing records; and

(B) a cement quality log or formation integrity test records;

(9) details that show that the inner and outer casing strings have sufficient strength in collapse and burst to withstand the anticipated pressure of disposal operations;

(10) downhole pressure obtained during a formation integrity test conducted below the outer casing shoe;

(11) identification of the hydrocarbon zones, if any, above the depth to which the inner casing is cemented;

(12) the duration of the disposal operation, not to exceed 90 days;

(13) whether drilling waste has previously been disposed of in the annular space of the well and, if so, a summary of the dates of the disposal operations, the

volumes of waste disposed of, and the wells where the drilling waste was generated;

(14) the well where the drilling waste to be disposed of was or will be generated;

(15) if the operator proposes not to comply with a limitation established in (d) of this section, an explanation of why compliance would be imprudent;

(16) any additional data required by the commission to confirm containment of drilling waste.

(c) The commission will authorize an annular disposal operation described in the Application for Sundry Approvals, as that application has been supplemented under this section, and subject to any modifications prescribed by the commission, if the commission determines that the

(1) waste will be adequately confined;

(2) disposal will not

(A) contaminate freshwater, except to the extent allowed under (e)(91) of this section;

(B) cause drilling waste to surface;

(C) impair the mechanical integrity of any well; or

(D) damage a producing or potentially producing formation or impair the recovery of oil or gas from a pool; and

(3) disposal will not circumvent 20 AAC 25.252 or 20 AAC 25.412.

(d) Unless the operator demonstrates that compliance with a limitation established in (1) - (4) of this subsection is imprudent, the commission will not authorize disposal of drilling waste

(1) in a volume greater than 35,000 barrels through the annular space of a single well;

(2) for a period longer than one year through the annular space of a single well;

(3) into a hydrocarbon-bearing stratum; or

(4) through the annular space of a well not located on the same drill pad or platform as the drilling operation generating the drilling waste.

(e) On a case-by-case basis, and as the commission considers necessary to ensure that the standards in (c) of this section are met, the commission will impose conditions upon an authorization to dispose of drilling waste under this section. In addition, an authorization to dispose of drilling waste under this section is subject to the following conditions:

(1) drilling waste may not be disposed of into freshwater, unless the

(A) freshwater is identified in the Application for Sundry Approvals; and

(B) commission finds that the freshwater has a total dissolved solids content of more than 3,000 mg/l, and is not reasonably expected to supply a public water system; the commission will, in its discretion, provide 15 days notice and the opportunity for a public hearing in accordance with 20 AAC 25.540 before making that finding;

(2) the downhole disposal pressure may not exceed the downhole pressure obtained during the formation integrity test conducted below the outer casing shoe, or a higher pressure specified in the authorization upon the commission's finding that the higher pressure will not cause drilling waste to migrate above the confining zone;

(3) if drilling waste appears above the confining zone, the operator shall immediately cease disposal, notify the commission, and take appropriate remedial action;

(4) if the commission notifies the operator that disposal operations pose a threat to well integrity, safety, oil or gas recovery, or freshwater, except to the extent allowed under (1) of this subsection, the operator shall immediately cease disposal and take appropriate remedial action as approved or required by the commission.

(f) For each annular disposal operation authorized under this section, the operator shall report the following information to the commission on a Report of Annular Disposal (Form 10-423) not later than 30 days after the end of the period authorized for the disposal operation:

(1) the dates when disposal began and ended;

(2) the volume of drilling waste disposed of in each of the following categories:

(A) the aggregate of drilling wastes described in (h)(1) of this section;

(B) the aggregate of drilling wastes described in (h)(2) of this section; and

(C) each substance determined to be a drilling waste under (h)(3) of this section.

(g) The provisions of 20 AAC 25.252 and 20 AAC 25.402 - 20 AAC 25.460 do not apply to the disposal of drilling waste authorized under this section.

(h) In this section, "drilling waste" means the following substances, unless identified as a hazardous waste in 40 C.F.R. 261:

(1) drilling mud, drilling cuttings, reserve pit fluids, cement-contaminated drilling mud, completion fluids, formation fluids associated with the act of drilling a well permitted under 20 AAC 25.005, and any added water needed to facilitate pumping of drilling mud or drilling cuttings;

(2) drill rig wash fluids and drill rig domestic waste water; and

(3) other substances that the commission determines upon application are wastes associated with the act of drilling a well permitted under 20 AAC 25.005.

(i) For purposes of this section, in AS 31.05.030 (e)(2), "oil or gas well" means a well permitted under AS 31.05.090 , other than a water well associated with oil or gas exploration and production.

ARIZONA

No requests have been received to date.

Determination would be made administratively on a case-by-case basis.

ARKANSAS

Limited number of requests received.

Administrative hearing procedures for operators who wish to use an alternative drilling waste technology in lieu of burial in closed pits.

CALIFORNIA

California Code of Regulations (CCR)

Title 14 (Natural Resources), Division 2 (Department of Conservation), Chapter 4 (Development, Regulation, and Conservation of Oil and Gas Resources), Subchapter 1 (Onshore Well Regulations), Article 3 (Requirements)

§1722. General.

…

(k) When sufficient geologic and engineering information is available from previous drilling, operators may make application to the supervisor for the establishment of field rules, or the supervisor may establish field rules or change established field rules for any oil or gas pool or zone in a field. Before establishing or changing a field rule, the supervisor shall distribute the proposed rule or change to affected persons and allow at least thirty (30) days for comments from the affected persons. The supervisor shall notify affected persons in writing of the establishment or change of field rules.

* * *

§1724.10. Filing, Notification, Operating, and Testing Requirements for Underground Injection Projects.

…

(i) To determine the maximum allowable surface injection pressure, a step-rate test shall be conducted prior to sustained liquid injection. Test pressure shall be from hydrostatic to the pressure required to fracture the injection zone or the proposed injection pressure, whichever occurs first. Maximum allowable surface injection pressure shall be less than the fracture pressure. The appropriate district office shall be notified prior to conducting the test so that it may be witnessed by a division inspector. The district deputy may waive or modify the requirement for a step-rate test if he or she determines that surface injection pressure for a particular well will be maintained considerably below the estimated pressure required to fracture the zone of injection.

COLORADO

No requests have been received to date.

Determination would be made on a case-by-case basis.

FLORIDA

Florida Administrative Code (FAC)

Chapter 62C-29 (Conservation of Oil and Gas: Injection Wells, Well Workovers, and Abandonments)

62C-29.001 General.

(1) All safety and environmental standards applicable to oil and gas wells are equally applicable to injection wells.

(2) Pressure Maintenance Wells. Regulations governing the drilling of oil, gas, or saltwater disposal wells apply equally to pressure maintenance wells.

(3) Monitoring. All injection wells shall be equipped with pressure gauges to monitor the tubing and tubing-casing annulus. Injection pressures and volumes shall be read and recorded weekly. If a malfunction or failure is detected, operators shall cease injection until the well is repaired and retested in accordance with 62C-29.007.

(4) The operator of each injection well shall file Form 10A, Monthly Well Injection Report (62C-25.008) with the Department within 30 days subsequent to the report period.

(5) All injection wells shall be visually inspected at quarterly intervals; pressure gauges shall be calibrated or proven quarterly and reported on Form 10A.

Specific Authority 377.22 FS. Law Implemented 377.22, 377.371 FS. History--New 11-26-81, Formerly 16C-29.01, Amended 6-4-89, 5-12-93, Formerly 16C-29.001, Amended 3-24-96.

62C-29.002 Injection Wells.

(1) Permits, as specified in 62C-25.006, 62C-26.003, and (3) below are required prior to both spudding and operating a Class II well. Wells initially constructed for the production of oil or gas may be converted to injection wells but shall not be operated without an Operating Permit (Form 14) issued by the Department. Wells drilled or converted for injection purposes are subject to the same requirements of plugging and site restoration as oil or gas wells. For information regarding an Application for Permit to Operate Well (Form 14) see 62C-25.006, 62C-26.008, 62C-28.016, and this section.

(2) No subsurface formation or zone will be approved for fluid disposal if total dissolved solids of the formation fluid do not equal or exceed 10,000 ppm and chloride content does not equal or exceed 5,000 ppm.

(3) As part of the application for a permit required by (1) above the operator shall submit to the Department a written application containing at least the following information:

(a) In the case of a well already drilled, a detailed plan for workover together with an appropriate well log of the well with the proposed zone marked and a statement giving the name of the disposal formation. In the case of undrilled wells, the name of the formation or zone to be used for injection and its approximate depth. In addition, any of the information required in (b) through (h) below may also apply, depending on well history and data available in the file.

(b) A plat showing the location of the proposed injection well and all wells within a one-half mile radius thereof which penetrated the formation proposed for injection if the formation is non-productive and all wells within a two-mile radius thereof if the proposed injection zone is productive of oil or gas within two miles.

(c) The following data are required for each well identified on the plat required in paragraph (b) above:

1. A description of well type, character and amount of material being injected.

2. A description of well construction.

3. Depth of the injection zone.

4. Record of completion and plugging activities.

5. Additional information may be required by the Department to properly evaluate environmental impacts on a site specific basis.

(d) A statement of estimated daily volume of saltwater to be injected, and of the injection pressure anticipated.

(e) A statement of other known instances in which the proposed disposal zone has been used for saltwater disposal.

(f) A chemical analysis of a sample of the formation waters of the zone proposed for brine injection. This sample may be taken from the proposed injection well or from any suitable well within two miles of the proposed injection well. When the well is drilled, well logs must be run over the proposed injection zone. These logs must indicate that contained chlorides are no less than 5,000 parts per million (ppm).

(g) A statement that the proposed disposal well will be completed in a manner to insure that the disposal products are injected into the proposed injection zone and that provision has been made for adequate protection of freshwater aquifers and other zones of commercial value. A schematic diagram of the disposal well showing the casing and cementing program shall be attached together with an explanation thereof. Adequate provision must be made to insure that surface casing is set below the base of all underground sources of drinking water.

(h) All supporting interpretative geologic data shall be signed by a geologist licensed in Florida as required by Sections 492.111 and 492.116, F.S.

(4) Prior to the injection of saltwater, the operator shall obtain from the Department a permit to operate well (Form 14), and an agent of the Department shall inspect each completed disposal facility to insure compliance.

(5) The operator shall measure the amount of saltwater injected into each disposal well and shall submit Form 10A, Monthly Well Injection Report, to the Department within 25 days subsequent to the reported period.

(6) All injection wells shall be equipped with tubing and packer set no more than 100 feet above the injection zone unless otherwise specified by the Department.

(7) No injections shall be permitted using casing as the injection string, in the annulus between casing strings, or between casing and the well bore.

(8) The integrity of the casing and tubing strings for injection wells shall be pressure tested in the presence of an agent of the Department upon initial construction or conversion and within two year intervals thereafter. Wells drilled for the purpose of injection shall be initially tested in accordance with Chapter 62C-27. Initial testing for wells converted for injection purposes and all subsequent testing shall be in accordance with 62C-29.007. Exceptions to this testing schedule may be granted by the Department provided the operator proposes and agrees to follow equivalent means of monitoring

casing and tubing integrity. If the casing or tubing fails to hold the scheduled pressure during the test time specified, the well shall be shut in until successful remedial action and retests have been completed.

(9) Each permit for an injection well shall include a condition specifying the upper limit of allowable pressure.

Specific Authority 377.22 FS. Law Implemented 377.22 FS. History--New 11-26-81, Amended 4-12-83, 8-1-83, Formerly 16C-29.02, Amended 6-4-89, 5-12-93, Formerly 16C-29.002, Amended 3-24-96.

62C-29.003 Injection Wells for Pressure Maintenance. (REPEALED)

Specific Authority 377.22 FS. Law Implemented 377.22, 377.28 FS. History--New 11-26-81, Formerly 16C-29.03, Amended 6-4-89, Repromulgated 5-12-93, Formerly 16C-29.003, Repealed 3-24-96.

62C-29.004 Monitoring, Periodic Inspection and Record Keeping. (REPEALED)

Specific Authority 377.22 FS. Law Implemented 377.22, 377.28 FS. History--New 11-26-81, Formerly 16C-29.04, Amended 6-4-89, Repromulgated 5-12-93, Formerly 16C-29.004, Repealed 3-24-96.

62C-29.005 Workover Notification. (REPEALED)

Specific Authority 377.22 FS. Law Implemented 377.22 FS. History--New 11-26-81, Formerly 16C-29.05, Amended 6-4-89, 5-12-93, Formerly 16C-29.005, Repealed 3-24-96.

62C-29.006 Workover Operations.

(1) Notification. Each operator shall notify the Department's agent prior to commencing a workover operation or, during an emergency, as soon thereafter as possible.

(2) Blowout Preventer Requirements. All workover operations for Type I wells shall provide blowout preventer systems and tests which shall meet or exceed the requirements in Chapter 62C-27, F.A.C.

(3) Reporting Requirements. The operator shall submit to the Department within 30 days of completion of any workover operation a revised Well Record (Form 8).

Specific Authority 377.22 FS. Law Implemented 377.22 FS. History--New 11-26-81, Formerly 16C-29.06, Amended 6-4-89, Repromulgated 5-12-93, Formerly 16C-29.006, Amended 3-24-96.

62C-29.007 Pressure Tests.

(1) Type I Wells. The production casing, tubing, and packers in all Type I wells shall be tested to a pressure equivalent to the length of production casing multiplied by .1 psi/ft. This pressure shall be applied at the surface for 30 minutes with no more than a 10% pressure drop. If there is evidence of a leak or an invalid test, necessary remedial measures shall be taken, and the casting retested. This pressure test shall be conducted after every fishing job or if requested by the Department. All pressure tests shall be recorded on the driller's log.

(2) Type II Wells. The production casing, tubing, and packers in all Type II wells

shall be pressure tested in the same manner as Type I well except that the test pressure shall be half as great.

(3) Mechanical Integrity Tests. Pressure requirements for Class II MIT's shall be 1.15 times the actual injection pressure of the well being tested. If the pressure is applied to the back side of the tubing on the packer and injection casing, the required pressure shall be .2 psi/ft for new wells and .1 psi/ft for existing wells. Pressure requirements for Class II wells constituting very low environmental risk (injection pressures less than 250 psig, injecting only freshwater, etc.) shall be, upon request, set correspondingly lower.

(4) Any well showing pressure on the casinghead, or leaking fluids between the production casing and the next larger casing string, shall be tested and repaired in accordance with this section.

Specific Authority 377.22 FS. Law Implemented 377.22 FS. History--New 11-26-81, Formerly 16C-29.07, Amended 6-4-89, 5-12-93, Formerly 16C-29.007, Amended 3-24-96.

62C-29.008 Blowout Preventer Requirements for Workover Operations. (REPEALED)

Specific Authority 377.22 FS. Law Implemented 377.22 FS. History--New 11-26-81, Formerly 16C-29.08, Amended 6-4-89, Repromulgated 5-12-93, Formerly 16C-29.008, Repealed 3-24-96.

62C-29.009 Plugging and Abandonment of Wells.

Operators must obtain Department approval prior to commencing plugging operations. To apply, operators may contact either the Chief or his agent and request authorization to plug and abandon the well and restore the site. Operators must specify exactly how the well will be plugged and the site restored. Oral approval to plug and abandon shall be granted when the operator meets the criteria defined in this section.

(1) Pulling of Casing from an Abandoned Hole. Before pulling casing from an abandoned hole the operator shall obtain approval from the Department for reentry into the well. To apply, the operator must submit a written request to the Chief, Florida Geological Survey, 903 West Tennessee Street, Tallahassee, Florida 32304. The Department shall approve the request when the operator meets the criteria specified in this section. All requests shall contain an Organization Report (62C-25.008), Performance Surety (62C-26.002), well diagram, proposed procedure, and replugging schedule.

(2) Permanent Abandonment. The Department recognizes that no single plugging and restoration schedule can suffice for all wells. However, the following criteria will apply to most wells; others shall be handled in accordance with 62C-25.001(5).

(a) Uncased-hold plugs: Cement plugs shall be placed in uncased portions of wells as necessary to prevent the migration of formation fluids from one zone to another. These plugs shall be placed in accordance with the following criteria.

1. All nonproductive intervals containing shows of hydrocarbons shall be isolated from the wellbore by placing a minimum cement plug of 200 feet in length across the showing interval. Such plugs shall extend from 100 feet below to 100 feet above the show and shall be verified by either tagging with 15,000 pounds of drill stem weight or pumping sufficient excess cement to guarantee proper placement.

2. All nonproductive intervals which are or have been productive within 5 miles of the well being plugged shall be isolated and verified in accordance with (a)1. above.

3. All flows of saltwater requiring 12 or more pounds per gallon to control shall be isolated as in (a)1. above and the plugs verified by tagging with 15,000 pounds of drill stem weight.

4. Underground Sources of Drinking Water shall be isolated from adjoining saline zones by a minimum cement plug of 400 feet extending from 200 feet below to 200 feet above the base of the USDW. Such plugs shall be verified by tagging with sufficient drill stem weight to guarantee proper placement of the plug.

5. Freshwater zones shall be isolated from nonfreshwater zones as in (a)4. above and the plugs verified in a like manner.

6. All intervals between any of the above plugs may be filled with drilling fluid.

(b) Cased Hole Plugs:

1. Perforated Interval Plugs: No perforation shall be permitted to remain open upon abandonment. Either a cement retainer shall be set a minimum of 100 feet above the open perforation interval with cement squeezed into the perforation interval and 50 feet of cement placed on top of the retainer, or a 200 foot cement plug placed to extend from 100 feet below to 100 feet above the perforations. If a cement retainer is not used or does not hold pressure, this plug shall be verified by either tagging with 15,000 pounds of drill stem weight or by utilizing an amount of cement 100% in excess of that needed for the 200 foot plug. If cement can not be squeezed below a properly operating cement retainer, then a 200 foot cement plug shall be set on top of the retainer.

2. Casing Seat Plugs: Where there is open hole below any casing seat, a cement plug shall be placed at the base of the string, extending at a minimum from 150 feet below to 150 feet above the casing shoe. If a cement retainer is used, it should be set not less than 50 feet nor more than 100 feet above the casing shoe and the cement plug placed so that it will extend at least 100 feet below the casing shoe and 100 feet above the retainer. If a retainer is not used or fails to hold pressure, the plug shall be verified by tagging with 15,000 pounds of drill stem weight. In the event lost circulation conditions were encountered immediately below the casing shoe so that any attempted casing seat plug would be lost to the formations below, a permanent type bridge plug shall be set within 100 feet of the casing shoe and 200 feet of cement placed on top of the bridge plug. Regardless of the method used to set this plug, the pipe, unless it is to be cut and recovered, shall be tested by placing on it a minimum pump pressure of 1000 psig. No more than a 10% pressure drop during a 30 minute test period shall be allowed. If this test fails, necessary remedial measures shall be taken and the pipe retested and plugged in accordance with (a)4. above.

3. Casing-Stub Plugs. When casing is cut and recovered, a cement plug 200 feet in length shall be placed at the base of the cut so that the plug extends from 100 feet below to 100 feet above the stub. This plug shall be verified as directed by the Department's agent.

(c) Up Hole Plugs:

1. USDW Plugs. All casing strings not cemented to the surface shall be cut not less than 200 feet below the base of the deepest USDW and pulled out of the hole. A cement plug shall then be set across the USDW as described in (a)4. above. If the casing seat depth exceeds the required plug depth and cannot be cut and pulled out of the hole,

then the plug shall be set inside the casing.

2. Freshwater Plug. A cement plug shall be set across the freshwater interval as described in (a)5. above. If the surface casing seat depth exceeds the required plug depth, then the plug shall be set inside the surface casing.

3. Annular Space Plugs. No annular space connecting saline water intervals with freshwater intervals or the surface with the drilled hold below shall be allowed to exist. If such space exists it shall be destroyed by cutting and recovering the necessary casing strings as described in (c)1. above. In the event that it is physically impossible to recover such casing, the operator shall devise an alternate method to accomplish the same result. Such alternate method must have prior approval of the Department's agent.

4. Surface Plug. A 100-foot cement plug shall be placed in the top of the largest string of pipe cemented to the surface. This plug shall extend from the top of the casing downward the required distance. A 1/2 inch thick steel plate shall be welded across the top of the casing.

(d) Restoration of location.

1. Mud pits. All fluids and recoverable slurry that remain in the pits shall be either returned to the wellbore below all USDW during the process of plugging, placed between plugs in the casings, or removed to an approved land fill.

2. Drilling sites. The operator shall remove all waste, debris, and equipment and shall restore the site as necessary to prevent erosion, invasion of exotic species, interruption of sheetwater flow or other similar impacts. Land drilling sites and access roads shall be restored to the approximate original contour of the surface and revegetated with native vegetation. However, upon written request of the landowner, or the operator with the landowner's consent, and where other natural resources are not endangered, the Department shall permit alternate restoration standards, including landowner retention of the access road, pad, or other improvements.

3. All casing shall be cut off at least four feet below ground surface.

4. The operator shall file Form 16 immediately upon plugging any well. The comments section shall include a detailed plugging schedule plus a clearly differentiated description of all completed restoration work and work yet to be completed with time frame.

5. The Department shall perform a final inspection on each restored site before relieving the operator of liability under these rules.

(3) Temporary Abandonments. Any well which is to be temporarily abandoned shall be plugged in accordance with 62C-25.001.

Specific Authority 377.22 FS. Law Implemented 377.22, 377.24 FS. History--New 11-26-81, Amended 4-12-83, Formerly 16C-29.09, Amended 6-4-89, 5-12-93, Formerly 16C-29.009, Amended 3-24-96.

62C-29.010 Plugging Completion and Site Restoration Report (Form 16). (REPEALED)

Specific Authority 377.22 FS. Law Implemented 377.22 FS. History--New 11-26-81, Formerly 16C-29.10, Amended 6-4-89, 5-12-93, Formerly 16C-29.010, Repealed 3-24-96.

62C-29.011 Final Inspection. (REPEALED)

Specific Authority 377.22 FS. Law Implemented 377.22 FS. History--New 11-26-81, Formerly 16C-29.011, Repromulgated 5-12-93, Formerly 16C-29.011, Repealed 3-24-96.

62C-29.012 Wells Used for Freshwater Supply Wells. (REPEALED)

Specific Authority 377.22 FS. Law Implemented 377.22 FS. History--New 11-26-81, Formerly 16C-29.12, Amended 6-4-89, Repromulgated 5-12-93, Formerly 16C-29.012, Repealed 3-24-96.

ILLINOIS

No regulations, directives or policy statements on slurry fracture injection, sub-fracture injection, or annulus injection.

Requests have been received from operators to use drilling pit wastes for inter-plug fluids (spacers) during well plugging operations and for injection down the production-casing annulus of newly completed producing wells.

Determination made on a case-by-case basis.

INDIANA

No regulations for slurry fracture injection or sub-fracture injection. Annulus injection of any E&P waste not permitted.

Regulatory flexibility to approve technologies on a case-by-case basis if an operator gives valid proof that underground sources of drinking water will not be threatened

KANSAS

Kansas Administrative Regulations (KAR)

Agency 82 (Kansas Corporation Commission), Article 3 (***), Disposal and Enhanced Recovery Rules

82-3-400. APPLICATION, APPROVAL, PLACE OF INJECTION OR DISPOSAL, AND RECORDS; PENALTY.

(a) Enhanced recovery fluids injection or disposal operations and enhanced recovery natural gas injection or disposal operations shall be permitted only upon application to the conservation division and upon approval by the commission. Before any formations are approved for use, determinations shall be made that they are separated from fresh and usable water formations by impervious beds to give adequate protection to the fresh and usable water formations.

(b) In reviewing applications for injection or disposal wells, the protection of hydrocarbons and water resources and oil and gas advisory committee recommendations concerning safe depths for injection or disposal for all producing areas in the state shall be considered by the commission.

(c) If no additional information, including well logs, formation tests, water quality data, or water well data, is made available by the operator, table II, incorporated by reference in commission order, dated August 1, 1987, docket no. 156,397-C (C-22,607), hereby incorporated by reference, shall be used by the commission in determining the minimum depth for the injection of salt water.

(d) For all injection and disposal well applications which require wellhead pressure to inject fluids, filed on and after December 8, 1982, the operator shall inject the fluids through tubing under a packer set immediately above the uppermost perforation or open hole zone, except as provided in K.A.R. 82-3-404 . The packer shall be set opposite an interval of casing protected by cement.

(e) Each operator of an injection or disposal well that is injecting fluid into a subsurface formation shall:

    (1) Keep a current and accurate record to be preserved for five years of the amount and kind of fluid injected into the well; and

    (2) submit a report to the commission on or before March 1 of the following year showing for the previous calendar year the amount and kind of fluid injected or disposed of into each well and any other information that may be required.

(f) Emergency authority to inject or dispose of fluids at an alternate location, in the event a facility is shut-in for maintenance, testing, repairs or by order of the commission, may be granted by the commission.

(g) The failure to obtain commission approval before beginning injection or disposal operations shall be punishable by a penalty of $1,000 to first-time violators, $5,000 to second-time violators, and $10,000 and operator license review to third-time violators. In addition, each injection or disposal well found to be operating without commission approval shall be shut-in until compliance is achieved.

82-3-404. INJECTION OR DISPOSAL WELL TUBING AND PACKER REQUIREMENTS.

(a) After December 8, 1982, each well shall be equipped to inject through tubing below a packer. A packer run on the tubing shall be set in casing opposite a cemented interval at a point immediately above the uppermost perforation or open-hole interval. The annulus between the tubing and the casing shall be filled with a corrosion-inhibiting fluid or hydrocarbon liquid. With the approval of the commission, packerless or tubingless completions may be authorized under the provisions of subsections (b) or (c) of this regulation.

(b) Injection or disposal through tubing without a packer may be authorized by the commission if the following requirements are met:

(1) Surface wellhead injection pressure shall not exceed zero psig.

(2) The tubing shall be run to a depth equal to or below the uppermost perforation or open-hole of the injection interval.

(3) The annular space between the tubing and the casing shall be filled with a corrosion inhibiting fluid or hydrocarbon liquid that has a specific gravity less than 1.00, and that is displaced and maintained at a point within 50 feet of the bottom of the tubing.

(4) Each wellhead shall be equipped with a pressure observation valve on the tubing and the tubing-casing annulus.

(5) A positive annulus pressure shall be maintained and monitored.

(6) Annulus pressure and injection surface pressure shall be monitored and recorded monthly and kept by the operator for five years.

(7) All pressure readings recorded shall be taken during actual injection or disposal operations.

(c) Injection or disposal without tubing may be authorized by the commission if all five of the following criteria are continuously met during the life of the well.

(1) The casing shall be cemented continuously from setting depth to surface.

(2) Surface wellhead injection pressure shall be recorded monthly and kept by the operator for five years.

(3) All pressure readings recorded shall be taken during actual injection or disposal operations.

(4) Mechanical integrity tests shall be performed every five years by running a retrievable plug to a depth no more than 50 feet above the uppermost perforation or open-hole of the injection or disposal zone or by another method acceptable to the commission.

(5) It shall be the sole responsibility of the operator of the tubingless completion to maintain the well so that the mechanical integrity tests can be performed as specified, or the well shall be immediately plugged and abandoned by displacing cement from the bottom of the well to the surface.

KENTUCKY

EPA Region IV (DI) administers the Class II UIC program.

No statutes, regulations, or policies addressing slurry fracture injection, sub-fracture injection, or annular injection of drill cuttings.

EPA has allowed at least one operator to dispose of drilling waste down the annulus of a producing well on a one-time basis.

LOUISIANA

Louisiana Administrative Code (LAC)

Title 43 (Natural Resources), Part XIX (Office of Conservation,General Operations), Subpart 1 (Statewide Order No. 29-B)

Chapter 3. Standards of Practice

§315. Disposal of Reserve Pit Fluids by Subsurface Injection

A. General Provisions

1. The Disposal (subsurface injection) of drilling and workover waste fluids (including reserve pit fluids) into (1) a newly drilled well which is to be plugged and abandoned or (2) into the casing annulus of a well being drilled, a recently completed well, or a well which has been worked over is prohibited, except when such injection is conducted in accordance with the requirements of this Subparagraph.

2. Injection of drilling and workover waste fluids shall not commence until approval has been granted by the Office of Conservation. Operators may apply for approval when applying for a drilling permit. Approval for injection into a well will remain valid for subsequent workovers provided the criteria in §315.C below continue to be met.

3. Injection of drilling and workover waste fluids (including reserve pit fluids) shall be limited to injection of only those fluids generated in the drilling, stimulation or workover of the specific well for which authorization is requested. Reserve pit fluids may not be transported from one well location to another for injection purposes.

4. Injection of drilling and workover waste pit fluids into zones that have been tested for hydrocarbons or are capable of hydrocarbon production is prohibited, except as otherwise provided by the commissioner.

5. Pump pressure shall be limited so that vertical fractures will not extend to the base of the USDW and/or groundwater aquifer.

6. A drilling and workover waste fluids injection site may be inspected by a duly authorized representative of the commissioner prior to approval.

7. Drilling and workover waste fluids to be injected pursuant to the provisions of this Section are exempt from the testing requirements of §311.C.

B. Application Requirements

1. Prior to the onsite injection of reserve pit fluids, an application shall be filed by the well operator on the appropriate form. The original and one copy of the application (with attachments) shall be submitted to the Office of Conservation for review and approval.

2. An application for approval of reserve pit fluid injection shall include:

a. schematic diagram of well showing:
   - i. total depth of well,
   - ii. depths of top and bottom of all casing strings and the calculated top of cement on each,
   - iii. size of casing, and
   - iv. depth of the deepest USDW;

b. operating data:
   - i. maximum pressure anticipated, and

ii. estimated volume of fluids to be injected;

c. a copy of the electronic log of the well (if run) or a copy of the electric log of a nearby well;

d. additional information as the commissioner may require.

C. Criteria for Approval

1. Casing string injection may be authorized if the following conditions are met and injection will not endanger underground sources of drinking water:

a. Surface casing annular injection may be authorized provided the surface casing is set and cemented at least 200 feet below the base of the lowermost USDW, except as otherwise provided by the commissioner; or

b. Injection through perforations in the intermediate or production casing may be authorized provided that intermediate or production casing is set and cemented at least 200 feet below the base of the lowermost USDW, except as otherwise provided by the commissioner.

2. Surface casing open hole injection may be approved provided the surface casing is set and cemented at least 200 feet below the lowermost USDW and a cement plug of at least 100 feet has been placed across the uppermost potential hydrocarbon bearing zone.

Chapter 4. Pollution Control (Class II Injection Well Regulations)

§433. Disposal of E&P Wastes by Slurry Fracture Injection

A. Applicability. The regulations in this Section shall apply to all onsite or offsite Class II injection wells which inject RCRA exempt E&P Waste at pressures which exceed the fracture pressure of the injection interval.

B. Definitions

Confining Zone-the impermeable geologic formation that is located below the base of the USDW and which directly overlies and is contiguous with the injection zone.

Containment Zone-the geologic formation or formations intended to serve as a barrier to fracture height growth, but allowed to be partially penetrated by fractures created during authorized injection. The containment zone directly overlies and is contiguous with the injection interval.

Injection Interval-the geological formation targeted to receive the injected fluids. This interval is contained within the injection zone.

Injection Zone-that group of geologic formations which extend from the bottom of the lowermost injection interval to the top of the containment zone.

Slurry Fracture Injection-a process by which solid waste is ground, if necessary, and mixed with water or another liquid. The resulting slurry is then deposited into fractures created in the receiving formation by the hydraulic force of injection.

Source Water Protection Area-the surface and subsurface area surrounding a source of drinking water (a water well, a well field, or a surface intake), supplying a public water system, through which contaminants are reasonably likely to move toward and reach the source of drinking water. The Source Water Protection Program is under the jurisdiction of the Louisiana Department of Health and Hospitals and the Louisiana Department of Environmental Quality.

Zone of Endangering Influence-a defined area around an injection well, the radius of which is the lateral distance for which the pressures in the injection interval(s) may cause the vertical migration of injection and/or formation fluid out of the injection zone.

C. Application Requirements for Slurry Fracture Injection Wells

1. Each application for approval of a new slurry fracture injection well shall be filed on Form UIC-2 SFI (or latest revision) and shall be developed under the supervision of person(s) knowledgeable in all phases of slurry fracture injection permit application preparation. The original, signed by the operator, and one copy of the application with two complete sets of attachments shall be furnished to the commissioner.

2. The application for approval of a slurry fracture injection well shall be accompanied by:

a. a completed Form UIC-2 SFI (or latest revision);

b. a completed Form MD-10-R (or latest revision);

c. a map showing the disposal well for which a permit is sought, the Area of Review (AOR), and the following information:

i. the number or name and location of all existing producing wells, injection wells, abandoned wells, and dry holes within the AOR;

ii. identification of the surface owner of the land on which disposal is to be located within the AOR;

iii. identification of each operator with a producing leasehold within the AOR;

iv. surface bodies of water, mines (surface and subsurface), quarries, water wells (public and private), public water systems, and other pertinent surface features including residences and roads;

d. a schematic of the well showing:

i. the total depth, drilled out depth or plugged back depth of the well;

ii. the depth of the top and bottom of the perforated interval;

iii. the size of the casing, borehole and tubing, and the depth of the packer and bottom hole pressure sensor;

iv. the depths of the tops and bottoms of the casings and the amounts, formulation, and yields of the cement slurries used to cement each string of casing;

v. the depth of the base of the USDW;

vi. the depths of the tops and bottoms of the injection interval, the containment zone, the injection zone, and confining zone;

e. if the well has been drilled, a copy of the Well History and Work Resume Report (WH-1) and an electric log of the well. In the case of undrilled wells, a descriptive statement of the proposed injection interval giving its approximate depth, along with an electric log or radioactivity log of a nearby well, if available;

f. maps and cross sections that detail the local geology and hydrology. All maps shall be constructed on a 1:2000 scale and contain a legend and a north arrow. All control points and fault cuts shall be shown on all cross sections. At a minimum, the following maps and cross sections shall be submitted:

i. isopach maps of the injection interval or intervals, the containment zones, and the confining zone;

ii. a structure map of the top of the injection zone and confining zone;

iii. two structural cross sections transecting the AOR and extending from below the base of the injection zone to above the base of the USDW. The cross sections shall be at approximate right angles and extend beyond the limits of the AOR;

iv. a regional map contoured on the base of the USDW;

v. a map of all fault planes within the AOR;

vi. any other information required by the commissioner;

g. a tabulation of data on all wells that penetrate the proposed confining zone. Such data shall include a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the commissioner may require;

h. a tabulation of all freshwater wells of record within the AOR. Each freshwater well shall be identified by owner, type of well, depth and current status of the well. Include a laboratory analysis for pH, chloride (mg/l) and total dissolved solids (mg/l) of a water sample from each freshwater well. A DEQ certified laboratory must perform the require analyses. As deemed appropriate, additional test parameters may be required by the commissioner;

i. the following proposed operating data shall be submitted as part of the operator's application:

i. the average and maximum daily rate and volume of slurry to be injected;

ii. the average and maximum injection pressure;

iii. the proposed injection procedures (including storage and pre-injection treatment of the waste stream, and the well use schedule);

j. schematic or other appropriate drawings of the surface (well head and related appurtenances) and subsurface construction details of the system;

k. construction procedures including cementing and casing program, logging procedures, deviation checks, and a drilling, testing and coring program;

l. description of the bottom hole pressure sensor required in §433.G.4, which includes installation procedures and equipment specifications;

m. detailed discussion of the logging and testing programs required in §433.H;

n. a detailed description of the monitoring program proposed in order to meet the requirements of §433.I and if applicable, §433.E.4;

o. contingency plans to cope with all shut-ins or well failures so as to prevent the migration of fluids out of the injection zone;

p. for wells within the AOR (as defined in §433.D) which penetrate the proposed confining zone, but are not properly completed or plugged, the proposed corrective action to be taken under §433.F;

q. any additional information necessary to demonstrate that injection into the proposed injection interval or intervals will not initiate fractures in the confining zone that could allow fluid movement out of the injection zone, pursuant to §433.B.1;

r. any other information required by the commissioner to evaluate the proposed well.

3. Unless the application is for a commercial slurry fracture injection well and subject to the public notice requirements of §519.A and §529, all applications for slurry fracture injection must be advertised at least once by the applicant in a format acceptable to the commissioner in the official state journal, in the official journal of the affected parish and in the journal of general circulation in the area where the proposed well is to

be located, if different from the official parish journal. Interested parties shall have at least 15 days to provide comments and/or request a hearing.

4. Unless the application is for a commercial slurry fracture injection well and subject to the provisions for adequate closure in §505.C.11, all applications for slurry fracture injection wells shall contain a closure plan cost estimate in a format acceptable to the commissioner. If the well is permitted, the applicant shall provide a bond, letter of credit, certificates of deposit issued by and drawn on Louisiana banks, or any other evidence of equivalent financial security acceptable to the commissioner. The amount of financial security will be determined upon review of the closure cost estimate and will be reviewed annually.

D. Area of Review (AOR). The AOR for each slurry fracture injection well shall be the greater of the two following methods:

1. calculation of the zone of endangering influence, which is that area the radius of which is the lateral distance for which the pressures in the injection interval(s) may cause vertical migration of the injection and/or formation fluid out of the injection zone. The zone of endangering influence shall be calculated using an acceptable model designed for this purpose; or

2. a fixed radius of two miles from the injection well.

E. Geologic Criteria of the Injection and Confining Zones

1. A confining zone which is impermeable and laterally continuous throughout the injection well's AOR shall immediately overlie the containment zone. The confining zone is to have a minimum thickness of 50 feet and be capable of preventing any upward fluid movement from the injection zone. Therefore, applicants/operators of SFI wells must provide information showing that injection into the injection zone will not initiate fracturing of the confining zone or the extension of existing fractures into the confining zone.

2. A containment zone may consist of either a single impermeable layer with a minimum thickness of 500 feet, or be comprised of alternating impermeable and permeable layers with a net thickness of impermeable strata of at least 500 feet.

3. The injection zone and confining zone shall be free of any fault planes or other geological discontinuities which could serve to transmit the injected waste out of the injection zone. The area is to be adequately mapped with sufficient controls and resolution to identify these geologic discontinuities.

4. If the AOR lacks adequate well control points to map the geologic features of the injection, containment, and confining zones, seismic surveys with acceptable interpretation shall be required encompassing an area inclusive of the AOR plus an additional one mile in order to acquire the necessary information needed to verify that injected waste will not migrate out of the injection zone. If seismic data is inadequate for this purpose, the commissioner shall require the operator to implement a suitable monitoring program capable of tracking the lateral and vertical extension of fractures caused by injection and to detect possible movement of fluids out of the containment zone. Such monitoring programs may incorporate the use of monitor wells, surface and subsurface tiltmeters, microseismic monitoring techniques, logging programs, or other technologies suitable for this purpose and which are acceptable to the commissioner.

F. Corrective Action. Applicants shall identify all known wells within the injection well's AOR which penetrate the confining zone. For wells which are improperly sealed, completed, or abandoned, the applicant shall also submit a plan consisting of such steps or modifications as are necessary to prevent the movement of fluid out of the injection zone ("corrective action"). Where the plan is adequate, the commissioner shall incorporate it into the permit as a condition. Where the commissioner's review of an application indicates that the applicant's plan is inadequate, the commissioner shall require the applicant to revise the plan, prescribe a plan for corrective action as part of the permit, or deny the application. No owner or operator of a well may begin injection until all required corrective action has been taken.

G. Construction Requirements

1. Siting. All slurry fracture injection wells shall be sited in such a fashion that they inject into a formation which is beneath the lower most formation containing a USDW within a two mile radius of the well bore and meets the geologic criteria of the injection zone and confining zone prescribed in §433.E above. Location of a slurry fracture injection well so that its AOR extends into a Source Water Protection Area is prohibited.

2. Casing and Cementing. All slurry fracture injection wells shall be cased and cemented in accordance with the following criteria:

a. The operator shall install casing necessary to withstand collapse, bursting, tensile, and other stresses and shall be cemented in a manner which will anchor and support the casing. Safety factors in casing program design shall be of sufficient magnitude to provide optimum well control while drilling and to assure safe operations for the life of the well. New pipe or used pipe reconditioned and tested to assure that it will meet or exceed American Petroleum Institute (API) standards for new pipe shall be used in all casing strings.

b. Surface casing and long string casing strings shall be centralized by means of a sufficient number of centralizers spaced in a manner as to provide proper centralization of the casing string in the borehole prior to cementing.

c. Surface casing shall be set a minimum of one hundred feet below the base of the USDW and cemented to surface. Cemented to surface shall be considered in this section as having actual cement returns noted at the surface. If cement returns are not observed, the operator shall contact the Injection and Mining Division and obtain approval for the procedures to be used to perform any required additional cementing operations.

d. Cement shall be allowed to stand a minimum of 12 hours under pressure before initiating pressure test or drilling plug. Under pressure is complied with if one float valve is used or if pressure is held otherwise.

e. A minimum of 12 hours prior notification shall be given to the appropriate Injection and Mining Division Conservation Enforcement Agent for the purpose of witnessing all required casing pressure tests. If the Conservation Enforcement Agent fails to appear within the 12-hour notification period, the operator may proceed with the pressure test and file an affidavit of casing test (Form Csg-T) with the Injection and Mining Division within 20 days of reaching total depth.

f. Surface casing shall be tested at a surface pressure not less than the test pressure required in §109.B (or successor regulations). If at the end of 30 minutes the pressure gauge shows a drop in excess of 5 percent of test pressure, the operator shall be required to take such corrective measures as will ensure that such surface casing will hold said pressure for 30 minutes without a drop of more than 5 percent of the test pressure.

g. Long string casing shall be set through the injection zone and cemented at least to the top of the confining zone.

3. All slurry fracture injection wells shall be equipped with injection tubing and a packer. The packer shall be set in the long string casing no higher than 150 feet above the perforated interval.

4. The well shall be equipped with a down-hole sensor that directly measures the fluid pressure at depth no higher than 50 feet above the packer setting depth. The pressure sensor must be connected to a device at the surface which will enable a continuous recording of the well's bottom hole pressure information in digital format.

H. Logging and Testing Requirements. In addition to conformance with the logging and testing criteria contained in LAC 43:XIX.419.A or successor regulations, slurry fracture injection wells shall meet the following logging and testing requirements:

1. Open Hole Logging Requirements: A neutron/density porosity log of the injection and confining zone is required. An induction log shall be run to determine salinity levels. A spectral gamma ray log shall be run to determine baseline lithology of the subsurface prior to injection. All logs are to be run from surface to at least 50 feet below the injection zone.

2. Acoustic Logging Requirements: On a well that is to be completed with the intent for it to be used for slurry fracture injection, acoustic logs shall be required. An open hole acoustic log showing acoustic porosity and formation travel time shall be run from the surface to at least 50 feet below the injection zone. A synthetic seismogram is required to be submitted in order to predict fracture parameters and as a link to subsequent seismic interpretation (time based or four dimensional). VSP (Vertical Seismic Profiling) shall be run for lateral effect. Acoustic data may be run in various formats to identify reservoir and fracture parameters and to show containment of the waste stream within the containment and injection zones. The various formats may be surface-to-surface, well to surface, cross well, 2-dimensional, 3-dimensional and 4-dimensional data. All monitor wells shall be used for lateral offset of the VSP and the depth of investigation must match the dimensions of the disposal domain. Acoustic data must be obtained pre-injection, during injection and post-injection (after disposal operations cease and prior to plugging and abandoning the well) in order to show long term containment.

3. Cement Bond Logging Requirements

a. At the time of the initial completion, after long-string casing (to below the injection zone) has been set and cemented, a suitable, interpretable cement quality (bond) log shall be run. In an existing well, the tubing must be pulled and a suitable cement quality log run prior to permit approval. The log is to be run from surface to 50 feet below the base of the injection zone. The log must define both vertical and lateral cement quality.

b. The log is to have sufficient vertical, horizontal and radial resolution to identify the location of cement channels, micro-channels, bonding index, gas cut cement, voids or any other cement/bond problem that may exist. The log must show transit time, amplitude, variable density and radial bond quality (from interpretation). Log quality control must show cement type, additives, setting time and compressive strength (used in variable density log generation), proper tool centering, proper casing centering and sufficient cement sheath thickness, borehole fluids type, density, viscosity, pressure and temperature. In deviated wellbores, for adequate interpretation, effective tool centering must be seen. Matching casing size and weight must be correct on all interpretations. Where possible, the log must be correlated to shape and rugosity of the borehole (from open hole caliper and porosity/lithology logs). The log must also show line weight, line speed, casing collar locator and gamma ray for depth correlation.

c. A repeat section, showing good repeatability, must be run from the base of the injection zone to the base of the confining zone. Wellsite and shop tool calibrations are to be included on all logs.

4. A temperature and gamma ray base log shall be run prior to the initiation of any fractures. Subsequent radioactive tracer or temperature logs are to be run using a method approved by the Injection and Mining Division.

5. The operator shall conduct a step rate/pressure falloff test on the injection well prior to the initiation of injection operations in order to establish the initial fracture closure and extension pressures of the injection interval.

6. A pressure falloff test shall be performed on the well prior to the initiation of any fracturing in order to establish the reservoir transmissivity. The Injection and Mining Division shall be consulted on the procedure for running this test.

7. An extended falloff shall be conducted at least once every 7-day cyclic injection period. The falloff period shall be maintained until the measured pressure has essentially stabilized.

8. The logging requirements for existing wells converted to slurry fracture injection are the same as those required for newly drilled wells.

9. Any other well logs or tests required by the commissioner.

I. Monitoring Requirements

1. A monitoring program that ensures that the injection activity does not cause the migration of fluids above the confining zone shall be approved by the commissioner. This monitoring program may be inclusive of or in addition to the monitoring program required in §433.E.4.

2. All approved monitoring programs shall include the continuous monitoring and recording of bottom hole pressures, injection rates, the tubing and casing annulus pressure, injected fluid density and the cumulative volume of waste injected using a method approved by the commissioner. The origination, type and components of all injected waste streams are to be recorded and made available when requested.

3. The operator shall analyze the bottom hole pressure data daily to ensure that the pressure in the injection interval is not becoming abnormally pressurized as a result of injection. Also, abnormal extrapolated pressures (net losses) that cannot be associated with the injection volumes must be investigated immediately to ensure that fluids are not migrating out of the injection zone. Depending on the injected volumes, the formation pressure log must be history matched to predicted pressures.

4. Fracture height and length shall be evaluated by the operator on a minimum three month rotation, or as directed by the commissioner, utilizing a method approved by the commissioner.

5. The operator shall conduct periodic step-rate tests at least every three months. The commissioner may require more frequent step-rate tests in order to evaluate changes in formation parting pressures and in-situ stress conditions.

6. A cement bond log having the same presentation as the initial cement bond log shall be run annually to evaluate the effects of the previous years injection on the cement

column. If it is evident that the cement bonding is losing integrity, injection will be prohibited until such time the integrity of the cement column is restored.

J. Operational Requirements

1. Based on the results of the step rate/pressure falloff test outlined in §433.H.5 above, the maximum and minimum injection pressures and corresponding injection rates will be determined. Using the fracture extension pressure derived from the step rate test, the minimum allowed bottom hole injection pressure shall be assigned a value of 150 psi below the extension pressure. The maximum allowed bottom hole injection pressure shall be no greater than 75 percent of the burst pressure of the casing.

2. The initial maximum authorized injection rate (at the start up of operations) shall be limited to no more than 20 percent over the rate required to maintain fracture extension pressure. However, if the operator can demonstrate conclusively that a higher injection rate will not cause excessive fracture growth, a higher injection rate may be authorized by the commissioner. If an increase in injection rate is authorized, the maximum and minimum bottom hole injection pressures shall be adjusted accordingly.

3. If at any time the bottom hole injection pressure or injection rate varies from the authorized range, the operator shall immediately cease injection and notify the Injection and Mining Division.

4. Should any of the periodic step rate/pressure fall off tests indicate a change in parting pressures or fracture extension pressures has occurred, the commissioner shall have to option to amend the well's minimum and maximum bottom hole injection pressures and maximum allowed injection rate or to require that the well cease injection until such time that the operator has proven that fluids are not migrating above the containment zone.

5. If monitoring indicates possible communication between the tubing and the tubing and casing annulus, the operator shall immediately cease injection and notify the Injection and Mining Division. Injection may not commence until the mechanical integrity of the well is restored and verified by the Injection and Mining Division.

6. Injection is to be conducted on a cyclic basis with the injection occurring only during daylight hours.

7. If in the commissioner's determination, over- pressurization of the reservoir may cause the movement of fluid out of the injection zone, the commissioner shall suspend or revoke the well's permit to inject. Also, if the average reservoir pressure is subjected to any net decrease in pressure, the commissioner may suspend the well's permit until such threat is resolved.

K. Reporting Requirements

1. The operator shall maintain daily records for the following:

a. the bottom hole pressure at the start of injection;

b. the minimum and maximum injection pressures;

c. the injection rates at 1 hour intervals;

d. the composition of injected waste stream (random sampling) on a daily or batch basis;

e. the densities and viscosities of the waste stream at 1 hour intervals of injection;

f. the minimum and maximum pressures on the casing and tubing annulus.

2. In addition, the operator shall provide an explanation for any discrepancies in the bottomhole or surface pressures, densities, viscosities and injection rates in a comments

column. If an acceptable explanation for any discrepancy in this data is not provided, the commissioner may suspend the well's permit to inject until the operator provides this information.

3. This information, in addition to that required under §433.I.2 above, shall be maintained as a permanent record in the operator's files and shall be provided to the Injection and Mining Division upon request.

4. The operator shall provide to the Injection Mining Division weekly summary reports of:

a. the minimum and maximum pressures recorded during injection;

b. the minimum and maximum pressures recorded during falloffs;

c. the minimum and maximum pressures on the casing and tubing annulus;

d. the daily and weekly injected volumes;

e. the average density and viscosity of injected waste stream.

5. The operator shall provide the Injection and Mining Division each by no later than the third working day of each week the results of an analysis of all extended falloff periods occurring during the previous week's reporting period. Each analysis report shall include a log-log derivative plot of the falloff period with the different flow regimes identified thereon. A comprehensive analysis of the linear and radial flow regimes is required if present. A summary of the properties of the injected fluids used in the analysis and the injection rates observed during each injection period must be included in the report, in addition to any other information which may be pertinent to the results of the falloff analysis.

6. The operator shall provide a diskette or compact disk of the well's continuous bottom hole pressure and rate data for the reporting period in a format specified by the commissioner.

7. In addition, the operator shall provide an explanation for any discrepancies in the bottomhole or surface pressures, densities, viscosities and injection rates in a comments column of the report. If an acceptable explanation for any discrepancy in this data is not provided, the commissioner may suspend the well's permit to inject until the operator provides this information.

8. All records required in this section shall be maintained by the operator for the life of the well and shall be made available for review or submitted to the Office of Conservation upon request.

L. Permitting Requirements

1. Applicants and applications for slurry fracture injection wells must comply with the applicable public notice requirements of this Chapter.

2. Applications for slurry fracture injection of E&P Waste shall comply with the following two-part permitting procedures:

a. Part I-Permit to Construct

i. The initial application shall be reviewed for completeness, processed and upon meeting the permit requirements, a "Permit to Construct" shall be issued.

ii. "Permit to Construct" shall become null and void one year from the date of issuance.

iii. The commissioner may grant a one year extension from mitigating circumstances.

b. Part II-Permit to Inject

i. Upon completion of construction, the documentation required by the "Permit to Construct" shall be submitted to the Office of Conservation.

ii. If the submitted documentation indicates compliance with the “Permit to Construct” and that the well has been constructed as permitted and indicated in the application, a "Permit to Inject" shall be issued.

3. Slurry fracture injection wells permitted under the authority of this Section must comply with the applicable general requirements, public notice requirements, work permit requirements, legal permit conditions, permit transfer requirements, mechanical integrity pressure testing requirements, confinement of fluid requirements, and plugging and abandonment requirements of LAC 43:XIX.Chapter 4.

MICHIGAN

EPA Region V (DI) administers the Class II UIC program. Duplicate permitting process administered by the Michigan Department of Environmental Quality.

No requests for Michigan have been received relative to slurry fracture injection or downhole disposal of salt cuttings to date. Fracturing of the subsurface formations by injection would not be allowed.

The following are selected rules from Part 615, Supervisor of Wells of the Natural Resources and Environmental Protection Act 1994 PA 451, as amended.

DEPARTMENT OF ENVIRONMENTAL QUALITY
GEOLOGICAL AND LAND MANAGEMENT DIVISION
OIL AND GAS OPERATIONS

PART 7. DISPOSAL OF OIL OR GAS FIELD WASTE, OR BOTH

R 324.703 Disposal of oil or gas field fluid wastes, or both.

Rule 703. A permittee of a well shall inject oil or gas field fluid wastes, or both, into an approved underground formation in a manner that prevents waste. The disposal formation shall be isolated from fresh water strata by an impervious confining formation.

History: 1996 MR 9, Eff. Sep. 19, 1996.

R 324.704 Use of annular space for disposal prohibited; temporary exception.

Rule 704. A permittee of a well shall not dispose of fluid wastes in the annular space between strings of casing. The supervisor may grant a temporary exception to the prohibition if the supervisor determines that annular disposal will not damage underground fresh water, oil, gas, or other minerals.

History: 1996 MR 9, Eff. Sep. 19, 1996.

PART 8. INJECTION WELLS

R 324.801 Use of tubing, packer, and fluid.

Rule 801. (1) A permittee of a well shall ensure that the injection of fluid into a well is through adequate tubing and packer. During injection operations, the tubing to casing annulus shall be filled with a noncorrosive liquid. Injection wells utilized for gas storage are exempt from this rule.

(2) A permittee of a well shall ensure that surface access to all casing annulii is provided.

(3) A permittee of a well shall ensure that an injection well is constructed and operated so that the injection of fluids is confined to strata approved by the supervisor or authorized representative of the supervisor.

History: 1996 MR 9, Eff. Sep. 19, 1996.

R 324.802 Temporary authority to inject.

Rule 802. The supervisor may grant a permittee of a well temporary authorization, for a period of not more than 30 days, to inject fluid for the limited purpose of running injectivity tests. Injection wells utilized for gas storage are exempt from this rule.

History: 1996 MR 9, Eff. Sep. 19, 1996.

R 324.804 Maximum injection pressure.

Rule 804. During disposal operations, a permittee shall ensure that the surface injection pressure does not exceed a pressure determined by the following equation:

$$Pm = (fpg - 0.433\ sg)d$$

where

Pm = surface injection pressure
fpg = fracture pressure gradient (if unknown, assume 0.800)
sg = specific gravity of the injection liquid (if unknown, assume 1.2)
d = injection depth in feet (true vertical depth).

History: 1996 MR 9, Eff. Sep. 19, 1996.

MISSISSIPI

State Oil and Gas Board Statewide Rules and Regulations (Order No. 201-51)

Rule 63 (Underground Injection Control), Part 12 (Annular Disposal)

RULE 63. UNDERGROUND INJECTION CONTROL

…

12. Annular Disposal

The Board, may approve annular disposal of produced fluids for a period of not more than one (1) year, after notice and hearing provided that the outermost casing is properly cemented through the lowermost USDW. The applicant shall provide the Board a Radioactive Tracer Survey (accompanied by an interpretation of the survey by the company which performed the test) to prove that the injected fluid is entering the permitted zone and there are no leaks in the casing. The applicant shall furnish the board an economic study of the well and the economic alternative methods of disposal of produced fluids. No permit for annular injection will be granted where a viable economic alternative is found to exist.

MISSOURI

No requests have been received for injection of waste. Waste has been used as plugging material in conjunction with properly placed cement plugs.

Due to the shallow nature of the majority of producing and injection wells, these wells are commonly air drilled, generating only a minimum amount of waste material. Deeper wells may be drilled using mud rotary. Waste that is generated is most commonly buried on site.

Code of State Regulations (CSR)

Title 10 (Department of Natural Resources), Division 50 (Oil and Gas Council), Chapter 2 (Oil and Gas Drilling and Production)

10 CSR 50-2.060 Plugging and Abandonment

PURPOSE: This rule provides for the protection of both surface water and groundwater. Drilling muds, oil and water recovered from drilling or testing operations must be disposed of so that pollution of surface soil, ponds and streams is avoided. Fresh water strata are protected by casing set below the deepest zone that might contain fresh water. Dry holes must be plugged and abandoned in a manner that subsurface salt water or mineralized water will be confined to the stratum in which it occurs. Similarly, each oil or gas stratum penetrated by a well must be permanently sealed when abandoned to prevent contamination of fresh water supplies and also to prevent damage by water of any oil or gas stratum capable of producing in paying quantities. In certain logging procedures, a radioactive source (in a probe or sonde) is lowered into the borehole to provide certain subsurface data useful in exploration for oil and gas. Should this radioactive source contained in a logging tool be lost, certain procedures are prescribed to prevent the accidental or intentional mechanical disintegration of the radioactive source. Further, there are provisions for marking the well site permanently as a warning that a radioactive source has been abandoned in the well.

(1) Before beginning abandonment work on any well whether it is a drilling well, or a well drilled for oil or gas, for geologic information, or for gas storage, or for any other purpose, notice of intention to abandon the well shall be filed with the state geologist on approved form OGC-6. The notice shall include the details of the proposed abandonment procedure and whether any logging tool containing a radioactive source is being abandoned (see section (8) of this rule for radioactive source abandonment procedure). If necessary to avoid rig downtime, oral permission to abandon dry holes may be obtained by informing the state geologist of proposed abandonment procedures.

(2) In lieu of prior notice and approval by the state geologist (form OGC-6) the operator may elect to plug the hole from total depth to within plow depth of the surface with cement slurry, being no less than sixteen (16) pounds per gallon density. In such event,

form OGC-7 shall be forwarded to the state geologist within forty-eight (48) hours after completion.

(3) Before any well is abandoned, it shall be plugged in a manner which will confine permanently all oil, gas and water in the separate strata originally containing them. The plugging operation shall be accomplished by the proper use of mud-laden fluid, cement and plugs, used singly or in combination as may be approved by the state geologist.

(4) Drill holes in formations which contain oil or gas or from which oil or gas have been produced, or that have been used for injection, shall be plugged by placing cement from the base of the formation to a point no less than twenty-five feet (25') above the top of the formation.

(5) Appropriate means shall be taken to eliminate movement of surface water into a plugged well and to prevent pollution of sub-surface strata.

(6) Casing shall be cut off below plow depth except as may be approved by the state geologist to allow for the conversion of a well to a water supply well for use by a landowner. A well conversion agreement (form OGC-8) is available for use by the operator and land-owner in these instances.

(7) Within thirty (30) days after the completion of abandonment, the prescribed plugging record, form OGC-7, shall be executed and submitted to the state geologist.

(8) Before a radioactive source may be abandoned, the person, firm or corporation proposing the abandonment shall notify the state geologist. Wells in which radioactive sources are being abandoned should be mechanically equipped so as to prevent the accidental or intentional mechanical disintegration of the radioactive source.

(A) Sources being abandoned in a well should be covered with no less than a fifty feet (50') standard-color-dyed cement plug on top of which a whipstock should be set. The dye is to alert the re-entry operator prior to encountering the source.

(B) In wells where a logging source has been cemented in place behind a casing string and above total depth, upon abandonment a standard-color-dyed cement plug should be placed opposite the abandoned source and to extend fifty feet (50') above and fifty feet (50’) below with a whipstock placed on top of the plug.

(C) In the event the operator finds that after expending a reasonable effort, because of hole conditions, it is not possible to abandon the source as prescribed in subsections (8)(A) or (B) of this rule, s/he shall seek the state geologist’s approval to cease efforts in this direction and obtain approval for an alternate abandonment procedure.

(9) Upon permanent abandonment of any well in which a radioactive source is left in the hole, and after removal of the wellhead, a permanent plaque is to be attached to the top of the casing left in the hole in a manner that re-entry cannot be accomplished without disturbing the plaque. This plaque would serve as a visual warning to any person re-entering the hole that a radioactive source has been abandoned in place in the well. The

plaque should contain the trefoil radiation symbol with a radioactive warning and should be constructed of a long-lasting material such as monel, stainless steel or brass.

(10) Monies deposited in the Oil and Gas Remedial Fund may be used by the council to plug those oil, gas and injection wells that have been abandoned and have not been plugged according to the council's rules, subject to the following guidelines:

(A) Wells covered by a forfeited bond shall receive first priority; and

(B) Other wells shall receive secondary priority on the basis of their potential for groundwater contamination or other damage in the order recommended to the council by the state geologist.

MONTANA

No statutes, regulations, or written policies prohibiting slurry fracture injection or any other related injection practice for the disposal of drilling pit waste.

Theoretically, an operator could file for a special permit.

NEBRASKA

No specific regulations addressing slurry fracture injection, sub-fracture injection, or annulus injection.

No requests have been received to date.

Determination would be made administratively on a case-by-case basis.

NEVADA

No regulations or policies for slurry fracture injection or other drilling waste related injection activities.

No requests have been received relative to slurry fracture injection.

A one-time disposal of drilling mud down the annulus of a producing well has occurred on land administered by the Bureau of Land Management.

NEW MEXICO

No specific regulations addressing slurry fracture injection, sub-fracture injection, or annular injection.

No requests have been received to date.

Broad administrative powers to allow experimental new technologies.

NEW YORK

No specific regulations, policies, or guidelines for slurry fracture injection, sub-fracture injection, or annulus disposal of drilling and reserve pit waste.

No requests for New York have been received by EPA Region II (DI) to date.

NORTH DAKOTA

North Dakota Industrial Commission
POLICY FOR ONSITE DOWNHOLE DISPOSAL OF DRILLING FLUIDS
(Revised August 17, 1998)

Guidelines for true annular disposal (pump down surface-production casing annulus):

1. Surface casing must be set 50 feet into Pierre Shale.
2. Surface casing CBL is required--bottom 500 feet minimum, no pressure required.
3. Surface casing must be pressure tested to 80% of burst pressure rating after drilling is completed and prior to running production casing.
4. Disposal pressure cannot exceed 75% of pressure test on surface casing.
5. Temperature log must be run before and after disposal.
6. Top of cement on production casing must be below Inyan Kara Formation.
7. Disposal only allowed in Inyan Kara Formation.
8. A block squeeze above Inyan Kara Formation after disposal is required.
9. Injection pressure must be continuously recorded.

Note: If surface casing pressure test fails, no injection is allowed. Any surface casing leak must be remediated (squeeze, etc.) prior to setting production casing.

* * *

Guidelines for open hole disposal (no production casing set, pump through drill pipe and retainer set at base of surface casing):

1. Surface casing must be set 50 feet into Pierre Shale.
2. Surface casing CBL is required--bottom 500 feet minimum, no pressure required.
3. Surface casing must be pressure tested to 80% of burst pressure rating.
4. Disposal pressure cannot exceed 75% of pressure test on surface casing.
5. Temperature log must be run before and after disposal.
6. A Cement plug must be set below the Dakota Group and must wait on cement 12 hours. If an accelerator is used, cement must have a compressive strength of 1000 psi.
7. Retainer or packer must be set at base of surface casing. Disposal must occur through drill pipe or tubing.
8. Disposal only allowed in Inyan Kara Formation.
9. Injection pressure must be continuously recorded.

Note: If surface casing pressure test fails, no injection is allowed. Location of leak in surface casing must be identified and isolated by placing cement across when plugging.

Note: Operator shall make application for approval. Each request considered on a case-by-case basis.

Calculating maximum surface injection pressure (open hole):

Surface casing test pressure = 0.8 * burst strength

Maximum surface injection pressure = (0.8 * burst strength) * (0.75 policy safety factor)

Example:

1950' of 8-5/8", 24#, K-55 Surface casing
Internal yield = 2950 psi

Surface casing test pressure = 0.8 * 2950 psi = 2360 psi

Maximum surface injection pressure = 2360 psi * 0.75 = 1770 psi

OHIO

Ohio Revised Code

Title [15] XV (Department of Natural Resources -- General Provisions), Chapter 1509 (Division of Mineral Resources Management -- Oil and Gas)

§ 1509.22 Contamination of water prohibited; storage and disposal of brine, duty to water user.

(A) Except when acting in accordance with section 1509.226 [1509.22.6] of the Revised Code, no person shall place or cause to be placed brine in surface or ground water or in or on the land in such quantities or in such manner as actually causes or could reasonably be anticipated to cause either of the following:

(1) Water used for consumption by humans or domestic animals to exceed the standards of the Safe Drinking Water Act;

(2) Damage or injury to public health or safety or the environment.

(B) No person shall store or dispose of brine in violation of a plan approved under division (A) of section 1509.222 [1509.22.2] or section 1509.226 [1509.22.6] of the Revised Code, in violation of a resolution submitted under section 1509.226 [1509.22.6] of the Revised Code, or in violation of rules or orders applicable to those plans or resolutions.

(C) The chief of the division of mineral resources management shall adopt rules and issue orders regarding storage and disposal of brine and other waste substances; however, the storage and disposal of brine and the chief's rules relating to storage and disposal are subject to all of the following standards:

(1) Brine from any well except an exempt Mississippian well shall be disposed of only by injection into an underground formation, including annular disposal if approved by rule of the chief, which injection shall be subject to division (D) of this section; by surface application in accordance with section 1509.226 [1509.22.6] of the Revised Code; in association with a method of enhanced recovery as provided in section 1509.21 of the Revised Code; or by other methods approved by the chief for testing or implementing a new technology or method of disposal. Brine from exempt Mississippian wells shall not be discharged directly into the waters of the state.

(2) Muds, cuttings, and other waste substances shall not be disposed of in violation of any rule;

(3) Pits may be used for containing brine and other waste substances resulting from, obtained from, or produced in connection with drilling, fracturing, reworking, reconditioning, plugging back, or plugging operations, but the pits shall be

constructed and maintained to prevent the escape of brine and other waste substances. A dike or pit may be used for spill prevention and control. A dike or pit so used shall be constructed and maintained to prevent the escape of brine, and the reservoir within such a dike or pit shall be kept reasonably free of brine and other waste substances.

(4) Earthen impoundments constructed pursuant to the division's specifications may be used for the temporary storage of brine and other waste substances in association with a saltwater injection well, an enhanced recovery project, or a solution mining project;

(5) No pit, earthen impoundment, or dike shall be used for the temporary storage of brine except in accordance with divisions (C)(3) and (4) of this section;

(6) No pit or dike shall be used for the ultimate disposal of brine.

(D) No person, without first having obtained a permit from the chief, shall inject brine or other waste substances resulting from, obtained from, or produced in connection with oil or gas drilling, exploration, or production into an underground formation unless a rule of the chief expressly authorizes the injection without a permit. The permit shall be in addition to any permit required by section 1509.05 of the Revised Code, and the permit application shall be accompanied by a permit fee of one hundred dollars. The chief shall adopt rules in accordance with Chapter 119. of the Revised Code regarding the injection into wells of brine and other waste substances resulting from, obtained from, or produced in connection with oil or gas drilling, exploration, or production. The rules shall include provisions regarding applications for and issuance of the permits required by this division; entry to conduct inspections and to examine and copy records to ascertain compliance with this division and rules, orders, and terms and conditions of permits adopted or issued under it; the provision and maintenance of information through monitoring, recordkeeping, and reporting; and other provisions in furtherance of the goals of this section and the Safe Drinking Water Act. To implement the goals of the Safe Drinking Water Act, the chief shall not issue a permit for the injection of brine or other waste substances resulting from, obtained from, or produced in connection with oil or gas drilling, exploration, or production unless the chief concludes that the applicant has demonstrated that the injection will not result in the presence of any contaminant in ground water that supplies or can reasonably be expected to supply any public water system, such that the presence of the contaminant may result in the system's not complying with any national primary drinking water regulation or may otherwise adversely affect the health of persons. This division and rules, orders, and terms and conditions of permits adopted or issued under it shall be construed to be no more stringent than required for compliance with the Safe Drinking Water Act unless essential to ensure that underground sources of drinking water will not be endangered.

(E) The owner holding a permit, or an assignee or transferee who has assumed the obligations and liabilities imposed by this chapter and any rules adopted or orders issued under it pursuant to section 1509.31 of the Revised Code, and the operator of a well shall be liable for a violation of this section or any rules adopted or orders or terms or conditions of a permit issued under it.

(F) An owner shall replace the water supply of the holder of an interest in real property who obtains all or part of the holder's supply of water for domestic, agricultural, industrial, or other legitimate use from an underground or surface source where the supply has been substantially disrupted by contamination, diminution, or interruption proximately resulting from the owner's oil or gas operation, or the owner may elect to compensate the holder of the interest in real property for the difference between the fair market value of the interest before the damage occurred to the water supply and the fair market value after the damage occurred if the cost of replacing the water supply exceeds this difference in fair market values. However, during the pendency of any order issued under this division, the owner shall obtain for the holder or shall reimburse the holder for the reasonable cost of obtaining a water supply from the time of the contamination, diminution, or interruption by the operation until the owner has complied with an order of the chief for compliance with this division or such an order has been revoked or otherwise becomes not effective. If the owner elects to pay the difference in fair market values, but the owner and the holder have not agreed on the difference within thirty days after the chief issues an order for compliance with this division, within ten days after the expiration of that thirty-day period, the owner and the chief each shall appoint an appraiser to determine the difference in fair market values, except that the holder of the interest in real property may elect to appoint and compensate the holder's own appraiser, in which case the chief shall not appoint an appraiser. The two appraisers appointed shall appoint a third appraiser, and within thirty days after the appointment of the third appraiser, the three appraisers shall hold a hearing to determine the difference in fair market values. Within ten days after the hearing, the appraisers shall make their determination by majority vote and issue their final determination of the difference in fair market values. The chief shall accept a determination of the difference in fair market values made by agreement of the owner and holder or by appraisers under this division and shall make and dissolve orders accordingly. This division does not affect in any way the right of any person to enforce or protect, under applicable law, the person's interest in water resources affected by an oil or gas operation.

(G) In any action brought by the state for a violation of division (A) of this section involving any well at which annular disposal is used, there shall be a rebuttable presumption available to the state that the annular disposal caused the violation if the well is located within a one-quarter mile radius of the site of the violation.

* * *

Ohio Administrative Code (OAC)

1501:9 (Division of Oil and Gas)

1501:9-3 (Saltwater Operation)

1501:9-3-11 Annular disposal.

(A) Approval required.

(1) Disposal of brine into any annular space of any well shall be prohibited except where approved in writing by the chief and performed in accordance with this rule. Said approval shall be subject to conditions required by the chief as are necessary to protect surface and subsurface soils and waters and to ensure the conservation of other natural resources.

(2) Each owner or his agent shall give the appropriate division inspector at least six hours' notice in advance of the time the cementing, of casing and hookup for annular disposal are to be performed. A division office shall be notified when the appropriate inspector cannot be contacted. Said work shall be done pursuant to the instructions of a representative of the division in accordance with Chapter <JL:JUMP,"1509","1_PORC"1509. of the Revised Code and the rules adopted thereunder. If at least six hours' notice is not given, annular disposal will not be authorized on the well.

(3) Approval for annular disposal shall be granted by the chief if the construction requirements in paragraph (B) of this rule have been satisfied and the mechanical integrity of the well has been demonstrated to the chief in accordance with paragraph (C)(2) of this rule.

(4) The chief may rescind approval for annular disposal where the owner or his agent fails to conduct annular disposal operations in accordance with Chapter <JL:JUMP,"1509","1_PORC"1509. of the Revised Code and the rules adopted thereunder.

(B) Construction requirements. Any well authorized to use annular disposal shall be constructed as follows:

(1) The surface casing of any annular disposal well permitted after the effective date of this rule shall be set and sealed with cement in accordance with the following standards:

(a) Surface casing requirements;

(i) Surface casing shall be set at least fifty feet below the base of the deepest underground source of water containing less than ten thousand mg/l total dissolved solids;

(ii) Surface casing shall be free of all apparent defects including but not limited to bent joints, split seams, stripped threads, and holes;

(iii) No cement baskets shall be used above the deepest underground source of drinking water unless a cement bond log is run to verify a continuous seal from the casing seat to the surface; and

(iv) No well shall be approved for annular disposal unless a division representative is present while casing is installed and cemented or unless an affidavit is submitted by the operator attesting to conditions subject to the requirements of paragraph (A)(2) of this rule.

(b) Cement requirements:

(i) Cement shall be mixed with fresh water;

(ii) Cement shall be circulated to surface by the pump and plug method;

(iii) The density of the cement circulated prior to dropping the top plug shall range within five per cent, plus or minus, of the "American Petroleum Institute" optimum density standard for the type of cement used;

(iv) The record of all cement and mix water additives and percentages by weight of mix water shall be included on the cement ticket;

(v) A copy of the cement ticket shall be supplied to the appropriate division inspector;

(vi) The cement head shall not be removed until the cement reaches a compressive strength of five hundred pounds per square inch (psi); and

(vii) Cement shall provide a continuous seal from the casing seat to the surface.

(2) Any annular disposal well being used for disposal of brine produced on an adjacent lease shall have surface-casing sealed by circulating cement to the surface.

(3) All brine shall be transported in a liquid tight piped system.

(4) The connection between the brine pipeline and the annulus of the annular disposal well shall be visible and accessible for inspection by the division.

(5) All annular systems shall be liquid tight.

(6) Any well permitted and authorized to use annular disposal prior to the effective date of this rule is exempted from these construction requirements if it meets the construction requirements that were in effect when the well was permitted.

(C) Mechanical integrity.

(1) An annular disposal well has mechanical integrity if:

(a) There is no significant leak in the surface casing; and

(b) There is no significant fluid movement into an underground source of drinking water through channels adjacent to the well bore.

(2) Prior to obtaining approval from the chief for the use of annular disposal and prior to commencement of injection of brine, each owner or his agent shall demonstrate that the well has mechanical integrity in the following manner:

(a) Cement records shall be accepted as demonstration that there is no significant fluid movement into an underground source of drinking water through channels adjacent to the injection well bore if all requirements of paragraph (B)(1) of this rule have been satisfied; and

(b) After the well has been drilled to the depth attained prior to running production casing, a temporary plug consisting of either a packer run on tubing, or an electric bridge plug run on a wireline, shall be set at the base of the surface casing. The surface casing shall be filled with fresh water, pressurized to three hundred psi and shut in. If the pressure of three hundred psi is maintained for fifteen minutes with no more than a five per cent decline, the demonstration that there is no significant leak in the casing is satisfied; or

(c) The positive differential gas pressure test may be performed as a demonstration of mechanical integrity; or

(d) Such other test approved by the chief.

(3) The owner or his agent shall demonstrate mechanical integrity for all annular disposal wells at least once every five years by use of a method approved by the chief. By written notice, the chief may require the owner or his agent to comply with a schedule describing when such demonstrations shall be made.

(D) Volume limitations.

(1) Any annular disposal well with surface casing sealed to the surface with prepared clay may be used to dispose of a maximum average of five barrels a day per year.

(2) Any annular disposal well with surface casing sealed by circulating cement to the surface may be used to dispose of a maximum average volume of ten barrels a day per year.

(E) Operating and monitoring requirements.

(1) Well identification. The following information shall be posted in a conspicuous place on or near the storage tank(s) of any annular disposal operation: owner's name, lease name, well number, permit number, county, township, and emergency telephone number. In addition, the permit number shall be displayed in a conspicuous place on or near the wellhead of any annular disposal well.

(2) If the chief has reason to believe that mechanical failures have occurred or that downhole problems exist at an annular disposal well that causes or could reasonably be anticipated to cause contamination of the land, surface waters, or subsurface waters, the chief may suspend the annular disposal operations until the owner demonstrates to the chief that the mechanical failures or downhole problems have been corrected. If the chief suspends annular disposal operations under this rule, the chief may require the owner or operator to test the well for mechanical failure or other problems. Any test conducted or corrective action taken shall be approved by the chief and conducted under the chief's supervision.

(3) If mechanical failures or downhole problems cause or could reasonably be anticipated to cause contamination of surface or subsurface soils or waters, the annular disposal well owner or operator shall immediately cease all annular disposal operations and immediately notify the division. Within five days of the incident, the owner or operators shall submit to the chief a written report which shall include a detailed description of the incident, the actions taken to correct the situation and the results of such action.

(4) A flow meter or other quantitative monitoring method shall be required if annular disposal is used.

(5) No pressure, except that created by the force of gravity, shall be applied to brine disposed of into an annular space unless otherwise approved by the chief.

(6) Disposal of brine transported to the annular disposal well by any means other than pipeline, either on lease or across lease lines, shall be prohibited.

(7) Under no circumstances shall liquids or waste matter from any source, other than brine or other waste substances resulting, obtained, or produced in connection with oil or gas drilling, exploration, or production on the same lease or, where authorized, on adjacent leases, be injected into any annular disposal well.

(8) The owner shall notify the chief in writing within fifteen days upon abandonment of annular disposal operations.

(9) When an annular disposal well becomes incapable of producing oil or gas, all annular disposal operations shall cease and the well shall be plugged and abandoned in accordance with Chapter <JL:JUMP,"1509","1_PORC"1509. of the Revised Code and any rules adopted thereunder.

(F) Reporting and recordkeeping requirements.

(1) A well completion record in accordance with section 1509.10 of the Revised Code and Chapter 1501:9-3 of the Administrative Code shall be filed with the division within thirty days after completion of any annular disposal well.

(2) The owner shall keep an accurate record of the volume of fluid injected and a copy of such record shall be furnished to the chief upon request. Such owner shall file an annual report with the chief, on or before the fifteenth day of April, setting forth the total volume of fluid injected during the preceding calendar year. Such report shall also contain, if applicable, a description of any mechanical failures or downhole problems, the actions taken to correct the situation, and the results of such actions as described in paragraph (E)(3) of this rule.

(3) The owner shall retain mechanical integrity test data and monitoring records for a period of not less than five years or until a subsequent mechanical integrity test is performed.

(G) Public notification and participation.

(1) All annular disposal applications submitted to the division shall be listed in the weekly circular as described in section <JL:JUMP,"1509.06","1_PORC"1509.06 of the Revised Code. Such listing shall contain at least the following information:

(a) The name and address of the applicant;

(b) The location of the proposed well;

(c) The fact that further information may be obtained by contacting either the applicant or the division;

(d) The address and phone number of the division; and

(e) The fact that for full consideration all comments or objections must be received by the division, in writing, within twenty calendar days of the date the weekly circular was received or posted.

(2) The weekly circular shall be made available to the general public or any other interested party at each county engineer's office where the proposed well is located and must be posted at the engineer's office and at each division office. In addition, the circular shall be available to subscribers or to anyone that requests the information for a minimal printing and administrative cost.

(3) Comments and objections.

(a) Any person desiring to comment or to submit an objection with reference to an application for a permit to construct, convert to, or operate an annular disposal well shall file such comments or objections, in writing, with the "Underground Injection Control Section, Division of Oil and Gas, Fountain Square, Columbus, Ohio 43224." Such comments or objections shall be filed with the division no later than twenty calendar days from receipt of the circular at the county engineer's office or division offices.

(b) If no objections are received within the twenty-day period, the chief shall consider that no objection exists and shall issue a permit unless he finds that the application does not comply with this rule or other applicable laws and rules, is in violation of law, jeopardizes public health or safety, or is not in accordance with good conservation practices.

(c) If an objection is received, the chief shall rule upon the validity of the objection. If, in the opinion of the chief, such objection is not relevant to the issues of public health or safety, or to good conservation practices, or is without substance and the permit otherwise meets all other requirements of this rule, a permit shall be issued. If the chief considers any objection to be relevant to the issues of public health or safety, or to good conservation practices, or to have substance, a hearing may be called within thirty days of receipt of the objection. Such hearing shall be held at the central office of the division or other location designated by the chief. Notice of the hearing shall be published in a newspaper of general circulation and sent by the chief to the applicant and to the person who filed the objection.

(d) If the chief finds, after hearing, and upon consideration of the evidence and the application, that the following conditions have been met, the application shall be approved and a permit conditionally issued; otherwise, the chief shall deny the permit by order:

(i) The application complies with the requirements of Chapter 1501-9-3 of the Administrative Code;

(ii) The method of injection proposed in the application will not be in violation of law; and

(iii) The proposed method of injection will not jeopardize public health or safety, or the conservation of natural resources.

(e) The chief shall issue a permit granting annular disposal or an order denying annular disposal within fifteen days after a hearing.

(f) A response to the comments as a final division action shall be prepared summarizing the substantive comments received and the disposition of the comments. These comments shall be available for viewing by the general public at the division's central office.

OKLAHOMA

Oklahoma Administrative Code (OAC)

Title 165 (Corporation Commission), Chapter 10 (Oil And Gas Conservation), Subchapter 5 (Underground Injection Control)

165:10-5-12. Application for administrative approval for the subsurface injection of onsite reserve pit fluids

Except upon a case-by-case approval of the Commission pursuant to 165:10-5-13, the subsurface injection of reserve pit fluids is prohibited into:

- (1) A newly drilled well which is to be plugged and abandoned, or
- (2) The casing annulus of:
  - (A) A well being drilled.
  - (B) A recently completed well.
  - (C) A well which has been worked over.

* * *

165:10-5-13. Application for permit for one time injection of reserve pit fluids

(a) General.

- (1) Injection of reserve pit fluids shall be limited to injection of only those fluids generated in the drilling, deepening, or workover of the specific well for which authorization is requested.
- (2) An annular injection site shall be inspected by a duly authorized representative of the Commission prior to injection.
- (3) The applicant shall file with the Underground Injection Control an affidavit of delivery or mailing not later than five days after the application is filed.
- (4) An operator who disposes of drilling fluid into the surface casing or annulus without approval from the Manager of Pollution Abatement shall be fined $2,500.00.

(b) Criteria for approval.

- (1) Casing string injection may be permitted if the following conditions are met and injection will not endanger treatable water:
  - (A) Surface casing injection may be authorized provided that surface casing is set and cemented at least 200 feet below the base of treatable water, except as otherwise provided by the Commission; or
  - (B) Intermediate casing injection may be authorized provided that intermediate casing is set at least 200 feet below the base of treatable water, except as otherwise provided by the Commission.
- (2) Injection pressure shall be limited so that vertical fractures will not extend to the base of treatable water.

(3) Required form and attachments. Each application for annular injection shall be submitted to the UIC Department on Form 1015T in quadruplicate. The forms must be properly completed and signed. Attached to one copy of the form shall be the following:
    (A) Affidavit of mailing a copy of the Form 1015T or Form 1000 to the landowner and to each operator of a producing lease within 1/2 mile of the subject well.
    (B) Cement Bond Log of subject well (if run).
(4) Expiration of the permit. The permit shall expire on its own terms three months after the date of issuance of the permit.

(c) Emergency authority to inject into the annulus. The Manager of the UIC Department may grant emergency authority to inject pit fluids into the annulus provided an imminent environmental endangerment exists.

(d) Protest period. If no protest is received within 15 days of the mailing of Form 1015T, the application shall be submitted for administrative approval. If a protest is received within the protest period, the operator shall, within 30 days, set and give proper notice of a date for hearing on the Pollution Docket before an Administrative Law Judge.

PENNSYLVANIA

EPA Region IV (DI) administers the Class II UIC program.

No statutes, regulations, or policies addressing slurry fracture injection, sub-fracture injection, or annular injection of drill cuttings.

Due to the number of air drilled wells in Pennsylvania, slurry fracture injection or other associated injection technologies are not practical.

SOUTH DAKOTA

No specific regulation addresses slurry fracture injection, sub-fracture injection or annular injection.

No requests have been received for slurry disposal. Any application for slurry injection could be handled administratively. Administrative approval of disposal of drilling pit contents down the annulus of a producing well unlikely.

TENNESSEE

EPA Region IV (DI) administers the Class II UIC program.

No statutes, regulations or policies addressing slurry fracture injection, sub-fracture injection, or annular injection of drill cuttings.

Broad administrative powers to allow experimental new technologies. Tennessee would defer to EPA with respect to any permit for subsurface injection of drilling waste.

TEXAS

Texas Administrative Code (TAC)

Railroad Commission of Texas Rules

Title 16 (Economic Regulation), Part 1 (Railroad Commission of Texas), Chapter 3 (Oil and Gas Division)

RULE §3.8
Water Protection

(a) The following words and terms when used in this section shall have the following meanings, unless the context clearly indicates otherwise.

(1) Basic sediment pit--Pit used in conjunction with a tank battery for storage of basic sediment removed from a production vessel or from the bottom of an oil storage tank. Basic sediment pits were formerly referred to as burn pits.

(2) Brine pit--Pit used for storage of brine which is used to displace hydrocarbons from an underground hydrocarbon storage facility.

(3) Collecting pit--Pit used for storage of saltwater prior to disposal at a tidal disposal facility, or pit used for storage of saltwater or other oil and gas wastes prior to disposal at a disposal well or fluid injection well. In some cases, one pit is both a collecting pit and a skimming pit.

(4) Completion/workover pit--Pit used for storage or disposal of spent completion fluids, workover fluids and drilling fluid, silt, debris, water, brine, oil scum, paraffin, or other materials which have been cleaned out of the wellbore of a well being completed or worked over.

(5) Drilling fluid disposal pit--Pit, other than a reserve pit, used for disposal of spent drilling fluid.

(6) Drilling fluid storage pit--Pit used for storage of drilling fluid which is not currently being used but which will be used in future drilling operations. Drilling fluid storage pits are often centrally located among several leases.

(7) Emergency saltwater storage pit--Pit used for storage of produced saltwater for limited period of time. Use of the pit is necessitated by a temporary shutdown of disposal well or fluid injection well and/or associated equipment, by temporary overflow of saltwater storage tanks on a producing lease or by a producing well loading up with formation fluids such that the well may die. Emergency saltwater storage pits may sometimes be referred to as emergency pits or blowdown pits.

(8) Flare pit--Pit which contains a flare and which is used for temporary storage of liquid hydrocarbons which are sent to the flare during equipment malfunction but which are not burned. A flare pit is used in conjunction with a gasoline plant, natural gas processing plant, pressure maintenance or repressurizing plant, tank battery, or a well.

(9) Fresh makeup water pit--Pit used in conjunction with drilling rig for storage of water used to make up drilling fluid.

(10) Gas plant evaporation/retention pit--Pit used for storage or disposal of cooling tower blowdown, water condensed from natural gas, and other wastewater generated at gasoline plants, natural gas processing plants, or pressure maintenance or repressurizing plants.

(11) Mud circulation pit--Pit used in conjunction with drilling rig for storage of drilling fluid currently being used in drilling operations.

(12) Reserve pit--Pit used in conjunction with drilling rig for collecting spent drilling fluids; cuttings, sands, and silts; and wash water used for cleaning drill pipe and other equipment at the well site. Reserve pits are sometimes referred to as slush pits or mud pits.

(13) Saltwater disposal pit--Pit used for disposal of produced saltwater.

(14) Skimming pit--Pit used for skimming oil off saltwater prior to disposal of saltwater at a tidal disposal facility, disposal well, or fluid injection well.

(15) Washout pit--Pit located at a truck yard, tank yard, or disposal facility for storage or disposal of oil and gas waste residue washed out of trucks, mobile tanks, or skid-mounted tanks.

(16) Water condensate pit--Pit used in conjunction with a gas pipeline drip or gas compressor station for storage or disposal of fresh water condensed from natural gas.

(17) Generator--Person who generates oil and gas wastes.

(18) Carrier--Person who transports oil and gas wastes generated by a generator. A carrier of another person's oil and gas wastes may be a generator of his own oil and gas wastes.

(19) Receiver--Person who stores, handles, treats, reclaims, or disposes of oil and gas wastes generated by a generator. A receiver of another person's oil and gas wastes may be a generator of his own oil and gas wastes.

(20) Director--Director of the Oil and Gas Division or his staff delegate designated in writing by the director of the Oil and Gas Division or the commission.

(21) Person--Natural person, corporation, organization, government or governmental subdivision or agency, business trust, estate, trust, partnership, association, or any other legal entity.

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

(23) To dewater--To remove the free water.

(24) To dispose--To engage in any act of disposal subject to regulation by the commission including, but not limited to, conducting, draining, discharging, emitting, throwing, releasing, depositing, burying, landfarming, or allowing to seep, or to cause or allow any such act of disposal.

(25) Landfarming--A waste management practice in which oil and gas wastes are mixed with or applied to the land surface in such a manner that the waste will not migrate off the landfarmed area.

(26) Oil and gas wastes--Materials to be disposed of or reclaimed which have been generated in connection with activities associated with the exploration, development, and production of oil or gas or geothermal resources, as those activities are defined in paragraph (30) of this subsection, and materials to be disposed of or reclaimed which have been generated in connection with activities associated with the solution mining of brine. The term "oil and gas wastes" includes, but is not limited to, saltwater, other mineralized water, sludge, spent drilling fluids, cuttings, waste oil, spent completion fluids, and other liquid, semiliquid, or solid waste material. The term "oil and gas wastes" includes waste generated in connection with activities associated with gasoline plants, natural gas or natural gas liquids processing plants, pressure maintenance plants, or repressurizing plants unless that waste is a hazardous waste as defined by the administrator of the United States Environmental Protection Agency pursuant to the federal Solid Waste Disposal Act, as amended (42 United States Code §6901 et seq.).

(27) Oil field fluids--Fluids to be used or reused in connection with activities associated with the exploration, development, and production of oil or gas or geothermal resources, fluids to be used or reused in connection with activities associated with the solution mining of brine, and mined brine. The term "oil field fluids" includes, but is not limited to, drilling fluids, completion fluids, surfactants, and chemicals used to detoxify oil and gas wastes.

(28) Pollution of surface or subsurface water--The alteration of the physical, thermal, chemical, or biological quality of, or the contamination of, any surface or subsurface water in the state that renders the water harmful, detrimental, or injurious to humans, animal life, vegetation, or property, or to public health, safety, or welfare, or impairs

the usefulness or the public enjoyment of the water for any lawful or reasonable purpose.

(29) Surface or subsurface water--Groundwater, percolating or otherwise, and lakes, bays, ponds, impounding reservoirs, springs, rivers, streams, creeks, estuaries, marshes, inlets, canals, the Gulf of Mexico inside the territorial limits of the state, and all other bodies of surface water, natural or artificial, inland or coastal, fresh or salt, navigable or nonnavigable, and including the beds and banks of all watercourses and bodies of surface water, that are wholly or partially inside or bordering the state or inside the jurisdiction of the state.

(30) Activities associated with the exploration, development, and production of oil or gas or geothermal resources--Activities associated with:

(A) the drilling of exploratory wells, oil wells, gas wells, or geothermal resource wells;

(B) the production of oil or gas or geothermal resources, including:

(i) activities associated with the drilling of injection water source wells that penetrate the base of usable quality water;

(ii) activities associated with the drilling of cathodic protection holes associated with the cathodic protection of wells and pipelines subject to the jurisdiction of the commission to regulate the production of oil or gas or geothermal resources;

(iii) activities associated with gasoline plants, natural gas or natural gas liquids processing plants, pressure maintenance plants, or repressurizing plants;

(iv) activities associated with any underground natural gas storage facility, provided the terms "natural gas" and "storage facility" shall have the meanings set out in the Texas Natural Resources Code, §91.173;

(v) activities associated with any underground hydrocarbon storage facility, provided the terms "hydrocarbons" and "underground hydrocarbon storage facility" shall have the meanings set out in the Texas Natural Resources Code, §91.201; and

(vi) activities associated with the storage, handling, reclamation, gathering, transportation, or distribution of oil or gas prior to the refining of such oil or prior to the use of such gas in any manufacturing process or as a residential or industrial fuel;

(C) the operation, abandonment, and proper plugging of wells subject to the jurisdiction of the commission to regulate the exploration, development, and production of oil or gas or geothermal resources; and

(D) the discharge, storage, handling, transportation, reclamation, or disposal of waste or any other substance or material associated with any activity listed in subparagraphs (A)-(C) of this paragraph, except for waste generated in connection with activities associated with gasoline plants, natural gas or natural gas liquids processing plants, pressure maintenance plants, or repressurizing plants if that waste is a hazardous waste as defined by the administrator of the United States Environmental Protection Agency pursuant to the federal Solid Waste Disposal Act, as amended (42 United States Code §6901, et seq.).

(31) Mined brine--Brine produced from a brine mining injection well by solution of subsurface salt formations. The term "mined brine" does not include saltwater produced incidentally to the exploration, development, and production of oil or gas or geothermal resources.

(32) Brine mining pit--Pit, other than a fresh mining water pit, used in connection with activities associated with the solution mining of brine. Most brine mining pits are used to store mined brine.

(33) Fresh mining water pit--Pit used in conjunction with a brine mining injection well for storage of water used for solution mining of brine.

(34) Inert wastes--Nonreactive, nontoxic, and essentially insoluble oil and gas wastes, including, but not limited to, concrete, glass, wood, metal, wire, plastic, fiberglass, and trash.

(35) Coastal zone--The area within the boundary established in Title 31, Texas Administrative Code, §503.1 (Coastal Management Program Boundary).

(36) Coastal management program (CMP) rules--The enforceable rules of the Texas Coastal Management Program codified at Title 31, Texas Administrative Code, Chapters 501, 505, and 506.

(37) Coastal natural resource area (CNRA)--One of the following areas defined in Texas Natural Resources Code, §33.203: coastal barriers, coastal historic areas, coastal preserves, coastal shore areas, coastal wetlands, critical dune areas, critical erosion areas, gulf beaches, hard substrate reefs, oyster reefs, submerged land, special hazard areas, submerged aquatic vegetation, tidal sand or mud flats, water in the open Gulf of Mexico, and water under tidal influence.

(38) Coastal waters--Waters under tidal influence and waters of the open Gulf of Mexico.

(39) Critical area--A coastal wetland, an oyster reef, a hard substrate reef, submerged aquatic vegetation, or a tidal sand or mud flat as defined in Texas Natural Resources Code, §33.203.

(40) Practicable--Available and capable of being done after taking into consideration existing technology, cost, and logistics in light of the overall purpose of the activity.

(b) No pollution. No person conducting activities subject to regulation by the commission may cause or allow pollution of surface or subsurface water in the state.

(c) Exploratory wells. Any oil, gas, or geothermal resource well or well drilled for exploratory purposes shall be governed by the provisions of statewide or field rules which are applicable and pertain to the drilling, safety, casing, production, abandoning, and plugging of wells.

(d) Pollution control.

(1) Prohibited disposal methods. Except for those disposal methods authorized for certain wastes by paragraph (3) of this subsection, subsection (e) of this section, or §3.98 of this title (relating to Standards for Management of Hazardous Oil and Gas Waste), or disposal methods required to be permitted pursuant to §3.9 of this title (relating to Disposal Wells) (Rule 9) or §3.46 of this title (relating to Fluid Injection into Productive Reservoirs) (Rule 46), no person may dispose of any oil and gas wastes by any method without obtaining a permit to dispose of such wastes. The disposal methods prohibited by this paragraph include, but are not limited to, the unpermitted discharge of oil field brines, geothermal resource waters, or other mineralized waters, or drilling fluids into any watercourse or drainageway, including any drainage ditch, dry creek, flowing creek, river, or any other body of surface water. For any disposal method required to be permitted pursuant to §3.75 of this title (relating to Discharges to Waters of the State) (Rule 77), no permit issued under this section or authorization contained in this section satisfies the requirements of §3.75.

(2) Prohibited pits. No person may maintain or use any pit for storage of oil or oil products. Except as authorized by paragraph (4) or (7)(C) or (8) of this subsection, no person may maintain or use any pit for storage of oil field fluids, or for storage or disposal of oil and gas wastes, without obtaining a permit to maintain or use the pit. A person is not required to have a permit to use a pit if a receiver has such a permit, if the person complies with the terms of such permit while using the pit, and if the person has permission of the receiver to use the pit. The pits required by this paragraph to be permitted include, but are not limited to, the following types of pits: saltwater disposal pits; emergency saltwater storage pits; collecting pits; skimming pits; brine pits; brine mining pits; drilling fluid storage pits (other than mud circulation pits); drilling fluid disposal pits (other than reserve pits or slush pits); washout pits; and gas plant evaporation/retention pits. If a person maintains or uses a pit for storage of oil field fluids, or for storage or disposal of oil and gas wastes, and

the use or maintenance of the pit is neither authorized by paragraph (4) or (7)(C) or (8) of this subsection nor permitted, then the person maintaining or using the pit shall backfill and compact the pit in the time and manner required by the director. Prior to backfilling the pit, the person maintaining or using the pit shall, in a permitted manner or in a manner authorized by paragraph (3) of this subsection, dispose of all oil and gas wastes which are in the pit.

(3) Authorized disposal methods.

(A) Fresh water condensate. A person may, without a permit, dispose of fresh water which has been condensed from natural gas and collected at gas pipeline drips or gas compressor stations, provided the disposal is by a method other than disposal into surface water of the state.

(B) Inert wastes. A person may, without a permit, dispose of inert and essentially insoluble oil and gas wastes including, but not limited to, concrete, glass, wood, and wire, provided the disposal is by a method other than disposal into surface water of the state.

(C) Low chloride drilling fluid. A person may, without a permit, dispose of the following oil and gas wastes by landfarming, provided the wastes are disposed of on the same lease where they are generated, and provided the person has the written permission of the surface owner of the tract where landfarming will occur: water base drilling fluids with a chloride concentration of 3,000 milligrams per liter (mg/liter) or less; drill cuttings, sands, and silts obtained while using water base drilling fluids with a chloride concentration of 3,000 mg/liter or less; and wash water used for cleaning drill pipe and other equipment at the well site.

(D) Other drilling fluid. A person may, without a permit, dispose of the following oil and gas wastes by burial, provided the wastes are disposed of at the same well site where they are generated: water base drilling fluid which had a chloride concentration in excess of 3,000 mg/liter but which have been dewatered; drill cuttings, sands, and silts obtained while using oil base drilling fluids or water base drilling fluids with a chloride concentration in excess of 3,000 mg/liter; and those drilling fluids and wastes allowed to be landfarmed without a permit.

(E) Completion/workover pit wastes. A person may, without a permit, dispose of the following oil and gas wastes by burial in a completion/workover pit, provided the wastes have been dewatered, and provided the wastes are disposed of at the same well site where they are generated: spent completion fluids, workover fluids, and the materials cleaned out of the wellbore of a well being completed or worked over.

(F) Effect on backfilling. A person's choice to dispose of a waste by methods authorized by this paragraph shall not extend the time allowed for backfilling any reserve pit, mud circulation pit, or completion/workover pit whose use or maintenance is authorized by paragraph (4) of this subsection.

(4) Authorized pits. A person may, without a permit, maintain or use reserve pits, mud circulation pits, completion/workover pits, basic sediment pits, flare pits, fresh makeup water pits, fresh mining water pits, and water condensate pits on the following conditions.

(A) Reserve pits and mud circulation pits. A person shall not deposit or cause to be deposited into a reserve pit or mud circulation pit any oil field fluids or oil and gas wastes, other than the following:

(i) drilling fluids, whether fresh water base, saltwater base, or oil base;

(ii) drill cuttings, sands, and silts separated from the circulating drilling fluids;

(iii) wash water used for cleaning drill pipe and other equipment at the well site;

(iv) drill stem test fluids; and

(v) blowout preventer test fluids.

(B) Completion/workover pits. A person shall not deposit or cause to be deposited into a completion/workover pit any oil field fluids or oil and gas wastes other than spent completion fluids, workover fluid, and the materials cleaned out of the wellbore of a well being completed or worked over.

(C) Basic sediment pits. A person shall not deposit or cause to be deposited into a basic sediment pit any oil field fluids or oil and gas wastes other than basic sediment removed from a production vessel or from the bottom of an oil storage tank. Although a person may store basic sediment in a basic sediment pit, a person may not deposit oil or free saltwater in the pit. The total capacity of a basic sediment pit shall not exceed a capacity of 50 barrels. The area covered by a basic sediment pit shall not exceed 250 square feet.

(D) Flare pits. A person shall not deposit or cause to be deposited into a flare pit any oil field fluids or oil and gas wastes other than the hydrocarbons designed to go to the flare during upset conditions at the well, tank battery, or gas plant where the pit is located. A person shall not store liquid hydrocarbons in a flare pit for more than 48 hours at a time.

(E) Fresh makeup water pits and fresh mining water pits. A person shall not deposit or cause to be deposited into a fresh makeup water pit any oil and gas wastes or any oil field fluids other than water used to make up drilling fluid. A person shall not deposit or cause to be deposited into a fresh mining water pit any oil and gas wastes or any oil field fluids other than water used for solution mining of brine.

(F) Water condensate pits. A person shall not deposit or cause to be deposited into a water condensate pit any oil field fluids or oil and gas wastes other than fresh water condensed from natural gas and collected at gas pipeline drips or gas compressor stations.

(G) Backfill requirements.

(i) A person who maintains or uses a reserve pit, mud circulation pit, fresh makeup water pit, fresh mining water pit, completion/workover pit, basic sediment pit, flare pit, or water condensate pit shall dewater, backfill, and compact the pit according to the following schedule.

(I) Reserve pits and mud circulation pits which contain fluids with a chloride concentration of 6,100 mg/liter or less and fresh makeup water pits shall be dewatered, backfilled, and compacted within one year of cessation of drilling operations.

(II) Reserve pits and mud circulation pits which contain fluids with a chloride concentration in excess of 6,100 mg/liter shall be dewatered within 30 days and backfilled and compacted within one year of cessation of drilling operations.

(III) All completion/workover pits used when completing a well shall be dewatered within 30 days and backfilled and compacted within 120 days of well completion. All completion/workover pits used when working over a well shall be dewatered within 30 days and backfilled and compacted within 120 days of completion of workover operations.

(IV) Basic sediment pits, flare pits, fresh mining water pits, and water condensate pits shall be dewatered, backfilled, and compacted within 120 days of final cessation of use of the pits.

(V) If a person constructs a sectioned reserve pit, each section of the pit shall be considered a separate pit for determining when a particular section should be dewatered.

(ii) A person who maintains or uses a reserve pit, mud circulation pit, fresh makeup water pit, or completion/workover pit shall remain responsible for dewatering, backfilling, and compacting the pit within the time prescribed by clause (i) of this subparagraph, even if the time allowed for backfilling the pit extends beyond the expiration date or transfer date of the lease covering the land where the pit is located.

(iii) The director may require that a person who uses or maintains a reserve pit, mud circulation pit, fresh makeup water pit, fresh mining water pit, completion/workover pit, basic sediment pit, flare pit, or water condensate pit backfill the pit sooner than the time prescribed by clause (i) of this subparagraph if the director determines that oil and gas wastes or oil field fluids are likely to escape from the pit or that the pit is being used for improper storage or disposal of oil and gas wastes or oil field fluids

(iv) Prior to backfilling any reserve pit, mud circulation pit, completion/workover pit, basic sediment pit, flare pit, or water condensate pit whose use or maintenance is authorized by this paragraph, the person maintaining or using the pit shall, in a permitted manner or in a manner authorized by paragraph (3) of this subsection, dispose of all oil and gas wastes which are in the pit.

(5) Responsibility for disposal.

(A) Permit required. No generator or receiver may knowingly utilize the services of a carrier to transport oil and gas wastes if the carrier is required by this rule to have a permit to transport such wastes but does not have such a permit. No carrier may knowingly utilize the services of a second carrier to transport oil and gas wastes if the second carrier is required by this rule to have a permit to transport such wastes but does not have such a permit. No generator or carrier may knowingly utilize the services of a receiver to store, handle, treat, reclaim, or dispose of oil and gas wastes if the receiver is required by statute or commission rule to have a permit to store, handle, treat, reclaim, or dispose of such wastes but does not have such a permit. No receiver may knowingly utilize the services of a second receiver to store, handle, treat, reclaim, or dispose of oil and gas wastes if the second receiver is required by statute or commission rule to have a permit to store, handle, treat, reclaim, or dispose of such wastes but does not have such a permit. Any person who plans to utilize the services of a carrier or receiver is under a duty to determine that the carrier or receiver has all permits required by the Oil and Gas Division to transport, store, handle, treat, reclaim, or dispose of oil and gas wastes.

(B) Improper disposal prohibited. No generator, carrier, receiver, or any other person may improperly dispose of oil and gas wastes or cause or allow the improper disposal of oil and gas wastes. A generator causes or allows the improper disposal of oil and gas wastes if:

(i) the generator utilizes the services of a carrier or receiver who improperly disposes of the wastes; and

(ii) the generator knew or reasonably should have known that the carrier or receiver was likely to improperly dispose of the wastes and failed to take reasonable steps to prevent the improper disposal

(6) Permits.

(A) Standards for permit issuance. A permit to maintain or use a pit for storage of oil field fluids or oil and gas wastes may only be issued if the commission determines that the maintenance or use of such pit will not result in the waste of oil, gas, or geothermal resources or the pollution of surface or subsurface waters. A permit to dispose of oil and gas wastes by any method, including disposal into a pit, may only be issued if the commission determines that the disposal will not result in the waste of oil, gas, or geothermal resources or the pollution of surface or subsurface water. A permit to maintain or use any unlined brine mining pit or any unlined pit, other than an emergency saltwater storage pit, for storage or disposal of oil field brines, geothermal resource waters, or other mineralized waters may only be issued if the commission determines that the applicant has conclusively shown that use of the pit cannot cause pollution of surrounding productive agricultural land nor pollution of surface or subsurface water, either because there is no surface or subsurface water in the area of the pit, or because the surface or subsurface water in the area of the pit would be physically isolated by naturally occurring impervious barriers from any oil and gas wastes which might escape or migrate from the pit. Permits issued pursuant to this paragraph will contain conditions reasonably necessary to prevent the waste of oil, gas, or geothermal resources and the pollution of surface and subsurface waters. A permit to maintain or use a pit will state the conditions under which the pit may be operated, including the conditions under which the permittee shall be required to dewater, backfill, and compact the pit. Any permits issued pursuant to this paragraph may contain requirements concerning the design and construction of pits and disposal facilities, including requirements relating to pit construction materials, dike design, liner material, liner thickness, procedures for installing liners, schedules for inspecting and/or replacing liners, overflow warning devices, leak detection devices, and fences. However, a permit to maintain or use any lined brine mining pit or any lined pit for storage or disposal of oil field brines, geothermal resource waters, or other mineralized waters will contain requirements relating to liner material, liner thickness, procedures for installing liners, and schedules for inspecting and/or replacing liners.

(B) Application. An application for a permit to maintain or use a pit or to dispose of oil and gas wastes shall be filed with the commission in Austin. The applicant shall mail or deliver a copy of the application to the appropriate district office on the same day the original application is mailed or delivered to the commission in Austin. A permit application shall be considered filed with the commission on the date it is received by the commission in Austin. When a commission-prescribed application form exists, an applicant shall make application on the prescribed form according to the instructions on such form. The director may require the applicant to provide the commission with engineering, geological, or other information which the director deems necessary to show that issuance of the permit will not result in the waste of oil, gas, or geothermal resources or the pollution of surface or subsurface water.

(C) Notice. The applicant shall give notice of the permit application to the surface owners of the tract upon which the pit will be located or upon which the disposal will take place. When the tract upon which the pit will be located or upon which the disposal will take place lies within the corporate limits of an incorporated city, town, or village, the applicant shall also give notice to the city clerk or other appropriate official. Where disposal is to be by discharge into a watercourse other than the Gulf of Mexico or a bay, the applicant shall also give notice to the surface owners of each waterfront tract between the discharge point and 1/2 mile downstream of the discharge point except for those waterfront tracts within the corporate limits of an incorporated city, town, or village. When one or more waterfront tracts within 1/2 mile of the discharge point lie within the corporate limits of an incorporated city, town, or village, the applicant shall give notice to the city clerk or other appropriate official. Notice of the permit application shall consist of a copy of the application together with a statement that any protest to the application should be filed with the commission within 15 days of the date the application is filed with the commission. The applicant shall mail or deliver the required notice to the surface owners and the city clerk or other appropriate official on or before the date the application is mailed or delivered to the commission in Austin. If, in connection with a particular application, the director determines that another class of persons, such as offset operators, adjacent surface owners, or an appropriate river authority, should receive notice of the application, the director may require the applicant to mail or deliver notice to members of that class. If the director determines that, after diligent efforts, the applicant has been unable to ascertain the name and address of one or more persons required by this subparagraph to be notified, then the director may authorize the applicant to notify such persons by publishing notice of the application. The director shall determine the form of the notice to be published. The notice shall be published once each week for two consecutive weeks by the applicant in a newspaper of general circulation in the county where the pit will be located or the disposal will take place. The applicant shall file proof of publication with the commission in Austin. The director will consider the applicant to have made diligent efforts to ascertain the names and addresses of surface owners required by this subparagraph to be notified if the applicant has examined the current county tax rolls and investigated other reliable and readily available sources of information.

(D) Protests and hearings. If a protest from an affected person is made to the commission within 15 days of the date the application is filed, then a hearing shall be held on the application after the applicant requests a hearing. If the director has reason to believe that a person entitled to notice of an application has not received such notice within 15 days of the date an application is filed with the commission, then the director shall not take action on the application until reasonable efforts have been made to give such person notice of the application and an opportunity to file a protest to the application. If the director determines that a hearing is in the public interest, a hearing shall be held. A hearing on an application shall be held after the commission provides notice of hearing to all affected persons, or other persons or governmental entities who express an interest in the application in writing. If no protest from an affected person is received by the commission, the director may administratively approve the application. If the director denies administrative approval, the applicant shall have a right to a hearing upon request. After hearing, the hearings examiner shall recommend a final action by the commission.

(E) Modification, suspension, and termination. A permit granted pursuant to this paragraph, or a renewal permit granted pursuant to paragraph (7) of this subsection, or a permit which remains in effect pursuant to paragraph (7)(A) or (B) or (8) of this subsection, may be modified, suspended, or terminated by the commission for good cause after notice and opportunity for hearing. A finding of any of the following facts shall constitute good cause:

(i) pollution of surface or subsurface water is occurring or is likely to occur as a result of the permitted operations;

(ii) waste of oil, gas, or geothermal resources is occurring or is likely to occur as a result of the permitted operations;

(iii) the permittee has violated the terms and conditions of the permit or commission rules;

(iv) the permittee misrepresented any material fact during the permit issuance process;

(v) the permittee failed to give the notice required by the commission during the permit issuance process;

(vi) a material change of conditions has occurred in the permitted operations, or the information provided in the application has changed materially.

(F) Emergency permits. If the director determines that expeditious issuance of the permit will prevent or is likely to prevent the waste of oil, gas, or geothermal resources or the pollution of surface or subsurface water, the director may issue an emergency permit. An application for an emergency permit to use or maintain a pit or to dispose of oil and gas wastes shall be filed with the commission in the appropriate district office. Notice of the application is not required. If warranted by the nature of the emergency, the director may issue an emergency permit based upon a verbal application, or the director may verbally authorize an activity before issuing a written permit authorizing that activity. An emergency permit is valid for up to 30 days, but may be modified, suspended, or terminated by the director at any time for good cause without notice and opportunity for hearing. Except when the provisions of this subparagraph are to the contrary, the issuance, denial, modification, suspension, or termination of an emergency permit shall be governed by the provisions of subparagraphs (A)-(E) of this paragraph.

(G) Minor permits. If the director determines that an application is for a permit to store only a minor amount of oil field fluids or to store or dispose of only a minor amount of oil and gas waste, the director may issue a minor permit provided the permit does not authorize an activity which results in waste of oil, gas, or geothermal resources or pollution of surface or subsurface water. An application for a minor permit shall be filed with the commission in the appropriate district office. Notice of the application shall be given as required by the director. The director may determine that notice of the application is not required. A minor permit is valid for 30 days, but a minor permit which is issued without notice of the application may be modified, suspended, or terminated by the director at any time for good cause without notice and opportunity for hearing. Except when the provisions of this subparagraph are to the contrary, the issuance, denial, modification, suspension, or termination of a minor permit shall be governed by the provisions of subparagraphs (A)-(E) of this paragraph.

(7) Existing permits and pits (other than existing brine mining pit permits and brine mining pits).

(A) Existing permits. Each permit to maintain or use a lined or unlined pit for storage or disposal of oil field brines, geothermal resource water, or other mineralized waters, which has been issued by the commission prior to the effective date of this subsection, shall expire 180 days after the effective date of this subsection. Every other permit to store oil field fluids or oil and gas wastes or to dispose of oil and gas wastes, which permit has been issued by the commission prior to the effective date of this subsection, shall remain in effect until modified, suspended, or terminated by the commission pursuant to paragraph (6)(E) of this subsection. The permits which will expire pursuant to this paragraph include, but are not limited to, permits for the following types of pits: saltwater disposal pits, emergency saltwater storage pits, skimming pits, and brine pits.

(B) Renewal permits. Any person holding a permit scheduled to expire pursuant to subparagraph (A) of this paragraph may apply to the commission for renewal of the permit. If a person makes timely and sufficient application for renewal of a permit, then, notwithstanding the provisions of subparagraph (A) of this paragraph, the permit shall not expire until final commission action renewing or denying renewal of the permit. An application for renewal of a permit shall be filed with the commission in Austin within 180 days of the effective date of this subsection. No notice of the application is required. The director may administratively approve an application for renewal of a permit. No hearing shall be held on an application for renewal of a permit unless the applicant requests a hearing or the director determines that a hearing is necessary. No renewal permit will be issued unless the standards for permit issuance stated in paragraph (6)(A) of this subsection have been met.

(C) Operating existing unpermitted pits. If, as of the effective date of this subsection, a person is maintaining or using a pit, which is required by this subsection to be permitted but which was not required to be permitted prior to the effective date of this subsection, then the person maintaining or using the pit may continue to maintain or use the pit for 180 days after the effective date of this subsection. If a person makes timely and sufficient application for a permit to maintain or use such an existing but unpermitted pit, then the person may continue to use the pit until final commission action denying the permit. An application for a permit shall be considered timely if it is filed with the commission within 180 days of the effective date of this subsection. The issuance or denial of the permit shall be governed by the provisions of paragraph (6) of this subsection. The unpermitted pits, whose use or maintenance is authorized by this subparagraph, include, but are not limited to, the following types of pits: drilling fluid storage pits, gas plant evaporation/retention pits, and washout pits.

(D) Backfilling existing pits. If, as of the effective date of this subsection, a person is maintaining or using a basic sediment pit which does not meet the 50-barrel size limitation of paragraph (4)(C) of this subsection, then that person shall dewater, backfill, and compact the pit or rebuild the pit to comply with the 50-barrel size limitation within 180 days of the effective date of this subsection. Any person who, as of the effective date of the subsection, is maintaining or using a lined or unlined pit for storage or disposal of oil field brines, geothermal resource waters, or other mineralized waters, which pit was permitted prior to the effective date of this subsection, shall dewater, backfill, and compact the pit within 270 days of the effective date of this subsection unless the person applies for a renewal permit pursuant to subparagraph (B) of this paragraph. If a person applies for a renewal of a permit to maintain or use a lined or unlined pit for storage or disposal of oil filled brines, geothermal resource waters, or other mineralized waters, the director may extend the time for dewatering, backfilling, and compacting the pit to up to 90 days after final commission action denying renewal of the permit. If, as of the effective date of this subsection, a person is maintaining or using a pit, which is required by this subsection to be permitted but which was not required to be permitted prior to the effective date of this subsection, then the person maintaining or using the pit shall dewater, backfill, and compact the pit within 270 days of the effective date of this subsection unless the person applies for a permit to maintain or use the pit within the 180-day period allowed by subparagraph (C) of this paragraph. If a person applies for such a permit to maintain or use a previously unpermitted pit, the director may extend the time for dewatering, backfilling, and compacting the pit to up to 90 days after final commission action denying issuance of the permit. The director may require that pits required to be backfilled by this subparagraph be dewatered, backfilled, and compacted sooner than the time prescribed by this subparagraph if the director determines that oil and gas wastes are likely to escape from the pit or that the pit is being used for improper disposal of oil and gas wastes.

(8) Existing brine mining pit permits and brine mining pits. Existing brine mining pit permits and brine mining pits will be governed by the provisions of this paragraph rather than the provisions of paragraph (7) of this subsection.

(A) Existing brine mining pit permits. Any permit to maintain or use a brine mining pit, which permit has been issued by the commission prior to January 6, 1987, will remain in effect until modified, suspended, or terminated by the commission pursuant to paragraph (6)(E) of this subsection.

(B) Existing brine mining pits. If, as of January 6, 1987, a person is maintaining or using a brine mining pit and has not obtained a permit from the commission to maintain or use the pit, then the person may continue to use the pit through January 30, 1987. If the person makes timely and sufficient application for a permit to maintain or use the pit, then the person may continue to use the pit until final commission action denying the permit. An application for a permit to maintain or use the pit will be considered timely if it is filed with the commission by January 30, 1987. The issuance or denial of the permit will be governed by the provisions of paragraph (6) of this subsection. Unless the person maintaining or using the pit makes timely and sufficient application for a permit to maintain or use the pit, the person shall close the pit by May 1, 1987. If the person maintaining or using the pit makes timely and sufficient application for a permit to maintain or use the pit, but the permit is denied, then the person shall close the pit within 90 days after final commission action denying the permit. A pit required by this subparagraph to be closed shall be closed in accordance with a plan approved by the director. A closure plan must be submitted to the director for approval at least 60 days before the pit is required to be closed. The closure plan must describe the manner in which the pit will be dewatered or emptied, backfilled, and compacted. The director may require that a pit required to be closed by this subparagraph be closed sooner than the time prescribed by this subparagraph if the director determines that oil and gas wastes or oil field fluids are likely to escape from the pit or that the pit is being used for improper storage or disposal of oil and gas wastes or oil field fluids.

(9) Used oil. Used oil as defined in §3.98 of this title (relating to Standards for Management of Hazardous Oil and Gas Waste), shall be managed in accordance with the provisions of 40 CFR, Part 279.

(e) Pollution prevention (reference Order Number 20-59,200, effective May 1, 1969).

(1) The operator shall not pollute the waters of the Texas offshore and adjacent estuarine zones (saltwater bearing bays, inlets, and estuaries) or damage the aquatic life therein.

(2) All oil, gas, and geothermal resource well drilling and producing operations shall be conducted in such a manner to preclude the pollution of the waters of the Texas offshore and adjacent estuarine zones. Particularly, the following procedures shall be utilized to prevent pollution.

(A) The disposal of liquid waste material into the Texas offshore and adjacent estuarine zones shall be limited to saltwater and other materials which have been treated, when necessary, for the removal of constituents which may be harmful to aquatic life or injurious to life or property.

(B) No oil or other hydrocarbons in any form or combination with other materials or constituent shall be disposed of into the Texas offshore and adjacent estuarine zones.

(C) All deck areas on drilling platforms, barges, workover unit, and associated equipment both floating and stationary subject to contamination shall be either curbed and connected by drain to a collecting tank, sump, or enclosed drilling slot in which the containment will be treated and disposed of without causing hazard or pollution; or else drip pans, or their equivalent, shall be placed under any equipment which might reasonably be considered a source from which pollutants may escape into surrounding water. These drip pans must be piped to collecting tanks, sumps, or enclosed drilling slots to prevent overflow or prevent pollution of the surrounding water.

(D) Solid combustible waste may be burned and the ashes may be disposed of into Texas offshore and adjacent estuarine zones. Solid wastes such as cans, bottles, or any form of trash must be transported to shore in appropriate containers. Edible garbage, which may be consumed by aquatic life without harm, may be disposed of into Texas offshore and adjacent estuarine zones.

(E) Drilling muds which contain oil shall be transported to shore or a designated area for disposal. Only oil-free cutting and fluids from mud systems may be disposed of into Texas offshore and adjacent estuarine zones at or near the surface.

(F) Fluids produced from offshore wells shall be mechanically contained in adequately pressure-controlled piping or vessels from producing well to disposition point. Oil and water separation facilities at offshore and onshore locations shall contain safeguards to prevent emission of pollutants to the Texas offshore and adjacent estuarine zones prior to proper treatment.

(G) All deck areas on producing platforms subject to contamination shall be either curbed and connected by drain to a collecting tank or sump in which the containment will be treated and disposed of without causing hazard or pollution, or else drip pans, or their equivalent, shall be placed under any equipment which might reasonably be considered a source from which pollutants may escape into surrounding water. These drip pans must be piped to collecting tanks or sumps designed to accommodate all reasonably expected drainage. Satisfactory means must be provided to empty the sumps to prevent overflow.

(H) Any person observing water pollution shall report such sighting, noting size, material, location, and current conditions to the ranking operating personnel. Immediate action or notification shall be made to eliminate further pollution. The operator shall then transmit the report to the appropriate commission district office.

(I) Immediate corrective action shall be taken in all cases where pollution has occurred. An operator responsible for the pollution shall remove immediately such oil, oil field waste, or other pollution materials from the waters and the shoreline where it is found. Such removal operations will be at the expense of the responsible operator.

(3) The commission may suspend producing and/or drilling operations from any facility when it appears that the provisions of this rule are being violated.

(4) (Reference Order Number 20-60,214, effective October 1, 1970.) The foregoing provisions of Rule 8(D) shall also be required and enforced as to all oil, gas, or geothermal resource operations conducted on the inland and fresh waters of the State of Texas, such as lakes, rivers, and streams.

(f) Oil and gas waste haulers.

(1) A person who transports oil and gas waste for hire by any method other than by pipeline shall not haul or dispose of oil and gas waste off a lease, unit, or other oil or gas property where it is generated unless such transporter has qualified for and been issued an oil and gas waste hauler permit by the commission. Hauling of inert waste, asbestos-containing material regulated under the Clean Air Act (42 USC §§7401 et seq), polychlorinated biphenyl (PCB) waste regulated under the Toxic Substances Control Act (15 USCA §§2601 et seq), or hazardous oil and gas waste subject to regulation under §3.98 of this title (relating to Standards for Management of Hazardous Oil and Gas Waste), is excluded from this subsection. This subsection is not applicable to the hauling of oil and gas wastes for recycling. For purposes of this subsection, injection of salt water or other oil and gas waste into an oil and gas reservoir for purposes of enhanced recovery does not qualify as recycling. A person who has a salt water hauler permit does not need to apply for an oil and gas waste hauler permit until the person is scheduled to file an application for permit renewal.

(A) Application for an oil and gas waste hauler permit will be made on the commission-prescribed form, and in accordance with the instructions thereon, and must be accompanied by:

(i) the permit application fee required by §3.78 of this title (relating to Fees, Performance Bonds, and Alternate Forms of Financial Security Required To Be Filed) (Statewide Rule 78);

(ii) vehicle identification information to support commission issuance of an approved vehicle list;

(iii) an affidavit from the operator of each commission-permitted disposal system the hauler intends to use stating that the hauler has permission to use the system; and

(iv) a certification by the hauler that the vehicles listed on the application are designed so that they will not leak during transportation.

(B) An oil and gas waste hauler permit may be issued for a term not to exceed one year, subject to renewal by the filing of an application for permit renewal and the required application fee for the next permit period. The term of an oil and gas waste hauler permit will be established in accordance with a schedule prescribed by the director to allow for the orderly and timely renewal of oil and gas waste hauler permits on a staggered basis.

(C) Each oil and gas waste hauler shall operate in strict compliance with the instructions and conditions stated on the permit which provide:

(i) This permit, unless suspended or revoked for cause shown, shall remain valid until the expiration date specified in this permit.

(ii) Each vehicle used by a permittee shall be marked on both sides and the rear with the permittee's name and permit number in characters not less than three inches high. (For the purposes of this permit, "vehicle" means any truck tank, trailer tank, tank car, vacuum truck, dump truck, garbage truck, or other container in which oil and gas waste will be hauled by the permittee.)

(iii) Each vehicle must carry a copy of the permit including those parts of the commission-issued attachments listing approved vehicles and commission-permitted disposal systems that are relevant to that vehicle's activities. This permit authority is limited to those vehicles shown on the commission-issued list of approved vehicles.

(iv) This permit is issued pursuant to the information furnished on the application form, and any change in conditions must be reported to the commission on an amended application form. The permit authority will be revised as required by the amended application.

(v) This permit authority is limited to hauling, handling, and disposal of oil and gas waste.

(vi) This permit authorizes the permittee to use commission-permitted disposal systems for which the permittee has submitted affidavits from the disposal system operators stating that the permittee has permission to use the systems. These disposal systems are listed as an attachment to the permit. This permit also authorizes the permittee to use a disposal system operated under authority of a minor permit issued by the commission without submitting an affidavit from the disposal system operator. In addition, this permit authorizes the permittee to transport hazardous oil and gas waste to any facility in accordance with the provisions of §3.98 of this title (relating to Standards for the Management of Hazardous Oil and Gas Wastes), provided the shipment is accompanied by a manifest. Finally, this permit authorizes the transportation of oil and gas waste to a disposal facility permitted by another agency or another state provided the commission has granted separate authorization for the disposal.

(vii) The permittee must file an application for a renewal permit, using the permittee's assigned permit number, before the expiration date specified in this permit.

(viii) The permittee must compile and keep current a list of all persons by whom the permittee is hired to haul and dispose of oil and gas waste, and furnish such list to the commission upon request.

(ix) Each vehicle must be operated and maintained in such a manner as to prevent spillage, leakage, or other escape of oil and gas waste during transportation.

(x) Each vehicle must be made available for inspection upon request by commission personnel.

(2) A record shall be kept by each oil and gas waste hauler showing daily oil and gas waste hauling operations under the permitted authority.

(A) Such daily record shall be dated and signed by the vehicle driver and shall show the following information:

(i) identity of the property from which the oil and gas waste is hauled;

(ii) identity of the disposal system to which the oil and gas waste is delivered;

(iii) the type and volume of oil and gas waste received by the hauler at the property where it was generated; and

(iv) the type and volume of oil and gas waste transported and delivered by the hauler to the disposal system.

(B) Such record shall be kept open for the inspection of the commission or its representatives.

(C) Such record shall be kept on file for a period of three years from the date of operation and recordation.

(g) Recordkeeping.

(1) Oil and gas waste. When oil and gas waste is hauled by vehicle from the lease, unit, or other oil or gas property where it is generated to an off-lease disposal facility, the person generating the oil and gas waste shall keep, for a period of three years from the date of generation, the following records:

(A) identity of the property from which the oil and gas waste is hauled;

(B) identity of the disposal system to which the oil and gas waste is delivered;

(C) name and address of the hauler, and permit number (WHP number) if applicable; and

(D) type and volume of oil and gas waste transported each day to disposal.

(2) Retention of run tickets. A person may comply with the requirements of paragraph (1) of this subsection by retaining run tickets or other billing information created by the oil and gas waste hauler, provided the run tickets or other billing information contain all the information required by paragraph (1) of this subsection.

(3) Examination and reporting. The person keeping any records required by this subsection shall make the records available for examination and copying by members and employees of the commission during reasonable working hours. Upon request of the commission, the person keeping the records shall file such records with the commission.

(h) Penalties. Violations of this section may subject a person to penalties and remedies specified in the Texas Natural Resources Code, Title 3, and any other statutes administered by the commission. The certificate of compliance for any oil, gas, or geothermal resource well may be revoked in the manner provided in §3.68 of this title (relating to Pipeline Connection and Severance) (Rule 73) or violation of this section.

(i) Adoption of memorandum of understanding by reference. The memorandum of understanding between the Railroad Commission of Texas, the Texas Water Commission, and the Texas Department of Health, which concerns the division of jurisdiction among the agencies over wastes that result from, or are related to, activities associated with the exploration, development, and production of oil, gas, or geothermal resources, and the refining of oil, is adopted by reference. The effective date of the memorandum of understanding adopted by reference is December 1, 1987. Copies of the memorandum of understanding are available upon request from the

Railroad Commission of Texas, Oil and Gas Division, Underground Injection Control Section, P.O. Drawer 12967, Austin, Texas 78711-2967, (512) 463-6790.

(j) Consistency with the Texas Coastal Management Program. The provisions of this subsection apply only to activities that occur in the coastal zone and that are subject to the CMP rules.

(1) Specific Policies.

(A) Disposal of Oil and Gas Waste in Pits. The following provisions apply to oil and gas waste disposal pits located in the coastal zone:

(i) no commercial oil and gas waste disposal pit constructed after the effective date of this subsection shall be located in any CNRA; and

(ii) all oil and gas waste disposal pits shall be designed to prevent releases of pollutants that adversely affect coastal waters or critical areas.

(B) Discharge of Oil and Gas Waste to Surface Waters. The following provisions apply to discharges of oil and gas waste that occur in the coastal zone:

(i) no discharge of oil and gas waste to surface waters may cause a violation of the Texas Surface Water Quality Standards adopted by the Texas Natural Resource Conservation Commission and codified at Title 30, Texas Administrative Code, Chapter 307;

(ii) in determining whether any permit to discharge oil and gas waste that is comprised, in whole or in part, of produced water is consistent with the goals and policies of the CMP, the commission shall consider the effects of salinity from the discharge;

(iii) to the greatest extent practicable, in the case of any oil and gas exploration, production, or development operation from which an oil and gas waste discharge commences after the effective date this subsection, the outfall for the discharge shall not be located where the discharge will adversely affect any critical area;

(iv) in the case of any oil and gas exploration, production, or development operation with an oil and gas waste discharge permitted prior to the effective date of this subsection that adversely affects any critical area, the outfall for the discharge shall either:

(I) be relocated within two years after the effective date of this subsection, so that, to the greatest extent practicable, the discharge does not adversely affect any critical area; or

(II) the discharge shall be discontinued; and

(v) the commission shall notify the Texas Natural Resource Conservation Commission and the Texas Parks and Wildlife Department upon receipt of an application for a permit to discharge oil and gas waste that is comprised, in whole or in part, of produced waters to waters under tidal influence.

(C) Development in Critical Areas. The provisions of this subparagraph apply to issuance under §401 of the federal Clean Water Act, United States Code, Title 33, §1341, of certifications of compliance with applicable water quality requirements for federal permits authorizing development affecting critical areas. Prior to issuing any such certification, the commission shall confirm that the requirements of Title 31, Texas Administrative Code, §501.14(h)(1)(A)-(G), have been satisfied. The commission shall coordinate its efforts under this subparagraph with those of other appropriate state and federal agencies.

(D) Dredging and Dredged Material Disposal and Placement. The provisions of this subparagraph apply to issuance under §401 of the federal Clean Water Act, United States Code, Title 33, §1341, of certifications of compliance with applicable water quality requirements for federal permits authorizing dredging and dredged material disposal and placement in the coastal zone. Prior to issuing any such certification, the commission shall confirm that the requirements of Title 31, Texas Administrative Code, §501.14(j), have been satisfied.

(2) Consistency Determinations. The provisions of this paragraph apply to issuance of determinations required under Title 31, Texas Administrative Code, §505.30 (Agency Consistency Determination), for the following actions listed in Title 31, Texas Administrative Code, §505.11(a)(3): permits to dispose of oil and gas waste in a pit; permits to discharge oil and gas wastes to surface waters; and certifications of compliance with applicable water quality requirements for federal permits for development in critical areas and dredging and dredged material disposal and placement in the coastal area.

(A) The commission shall issue consistency determinations under this paragraph as an element of the permitting process for permits to dispose of oil and gas waste in a pit and permits to discharge oil and gas waste to surface waters.

(B) Prior to issuance of a permit or certification covered by this paragraph, the commission shall determine if the proposed activity will have a direct and significant adverse effect on any CNRA identified in the provisions of paragraph (1) of this subsection that are applicable to such activity.

(i) If the commission determines that issuance of a permit or a certification covered by this paragraph would not result in direct and significant adverse effects to any CNRA identified in the provisions of paragraph (1) of this subsection that are applicable to the proposed activity, the commission shall issue a written determination of no direct and significant adverse effect which shall read as follows: "The Railroad Commission has reviewed this proposed action for consistency with the Coastal Management Program (CMP) goals and policies, in accordance with the regulations of the Coastal Coordination Council (council), and has found that the proposed action will not have a direct and significant adverse affect on any coastal natural resource area (CNRA) identified in the applicable policies."

(ii) If the commission determines that issuance of a permit or certification covered by this paragraph would result in direct and significant adverse affects to a CNRA identified in the provisions of paragraph (1) of this subsection that are applicable to the proposed activity, the commission shall determine whether the proposed activity would meet the applicable requirements of paragraph (1) of this subsection.

(I) If the commission determines that the proposed activity would meet the applicable requirements of paragraph (1) of this subsection, the commission shall issue a written consistency determination which shall read as follows: "The Railroad Commission has reviewed this proposed action for consistency with the Texas Coastal Management Program (CMP) goals and policies, in accordance with the regulations of the Coastal Coordination Council (council), and has determined that the proposed action is consistent with the applicable CMP goals and policies."

(II) If the commission determines that the proposed activity would not meet the applicable requirements of paragraph (1) of this subsection, the commission shall not issue the permit or certification.

(3) Thresholds for Referral. Any commission action that is not identified in this paragraph shall be deemed not to exceed thresholds for referral for purposes of the CMP rules. Pursuant to Title 31, Texas Administrative Code, §505.32 (Requirements for Referral of an Individual Agency Action), the thresholds for referral of consistency determinations issued by the commission are as follows:

(A) for oil and gas waste disposal pits, any permit to construct a pit occupying five acres or more of any CNRA that has been mapped or that may be readily determined by a survey of the site;

(B) for discharges, any permit to discharge oil and gas waste consisting, in whole or in part, of produced waters into tidally influenced waters at a rate equal to or greater than 100,000 gallons per day;

(C) for certification of federal permits for development in critical areas:

(i) in the bays and estuaries between Pass Cavallo in Matagorda Bay and the border with the Republic of Mexico, any certification of a federal permit authorizing disturbance of:

(I) ten acres or more of submerged aquatic vegetation or tidal sand or mud flats; or

(II) five acres or more of any other critical area; and

(ii) in all areas within the coastal zone other than the bays and estuaries between Pass Cavallo in Matagorda Bay and the border with the Republic of Mexico, any certification of a federal permit authorizing disturbance of five acres or more of any critical area;

(D) for certification of federal permits for dredging and dredged material disposal or placement, certification of a permit authorizing removal of more than 10,000 cubic yards of dredged material from a critical area.

RULE §3.9
Disposal Wells

Any person who disposes of saltwater or other oil and gas waste by injection into a porous formation not productive of oil, gas, or geothermal resources shall be responsible for complying with this section, Texas Water Code, Chapter 27, and Title 3 of the Natural Resources Code.

(1) General. Saltwater or other oil and gas waste, as that term is defined in the Texas Water Code, Chapter 27, may be disposed of, upon application to and approval by the commission, by injection into nonproducing zones of oil, gas, or geothermal resources bearing formations that contain water mineralized by processes of nature to such a degree that the water is unfit for domestic, stock, irrigation, or other general uses. Every applicant who proposes to dispose of saltwater or other oil and gas waste into a formation not productive of oil, gas, or geothermal resources must obtain a permit from the commission authorizing the disposal in accordance with this section. Permits from the commission issued before the effective date of this section shall continue in effect until revoked, modified, or suspended by the commission.

(2) Geological requirements. Before such formations are approved for disposal use, the applicant shall show that the formations are separated from freshwater formations by impervious beds which will give adequate protection to such freshwater formations. The applicant must submit a letter from the Texas Natural Resource Conservation Commission, Austin, Texas, stating that the use of such formation will not endanger the freshwater strata in that area and that the formations to be used for disposal are not freshwater-bearing.

(3) Application. The application to dispose of saltwater or other oil and gas waste by injection into a porous formation not productive of oil, gas, or geothermal resources shall be filed with the commission in Austin accompanied by the prescribed fee. On the same date, one copy shall be filed with the appropriate district office.

(4) Commercial disposal well. An applicant for a permit to dispose of oil and gas waste in a commercial disposal well shall clearly indicate on the application and in the published notice of application that the application is for a commercial disposal well permit. For the purposes of this rule, "commercial disposal well" means a well whose owner or operator receives compensation from others for the disposal of oil field fluids or oil and gas wastes that are wholly or partially trucked or hauled to the well, and the primary business purpose for the well is to provide these services for compensation.

(5) Notice and opportunity for hearing.

(A) The applicant shall give notice by mailing or delivering a copy of the application to affected persons who include the owner of record of the surface tract on which the well is located; each commission-designated operator of any well located within one-half mile of the proposed disposal well; the county clerk of the county in which the well is located; and the city clerk or other appropriate city official of any city where the well is located within the municipal boundaries of the city, on or before the date the application is mailed to or filed with the commission. For the purposes of this section, the term "of record" means recorded in the real property or probate records of the county in which the property is located.

(B) In addition to the requirements of subsection (a)(5)(A) of this section, a commercial disposal well permit applicant shall give notice to owners of record of each surface tract that adjoins the proposed disposal tract by mailing or delivering a copy of the application to each such surface owner.

(C) If, in connection with a particular application, the commission or its delegate determines that another class of persons should receive notice of the application, the commission or its delegate may require the applicant to mail or deliver a copy of the application to members of that class. Such classes of persons could include adjacent surface owners or underground water districts.

(D) In order to give notice to other local governments, interested, or affected persons, notice of the application shall be published once by the applicant in a newspaper of general circulation for the county where the well will be located in a form approved by the commission or its delegate. The applicant shall file with the commission in Austin proof of publication prior to the hearing or administrative approval.

(E) Protested applications:

(i) If a protest from an affected person or local government is made to the commission within 15 days of receipt of the application or of publication, whichever is later, or if the commission or its delegate determines that a hearing is in the public interest, then a hearing will be held on the application after the commission provides notice of hearing to all affected persons, local governments, or other persons, who express an interest, in writing, in the application.

(ii) For purposes of this section, "affected person" means 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.

(F) If no protest from an affected person is received by the commission, the commission's delegate may administratively approve the application. If the commission's delegate denies administrative approval, the applicant shall have a right to a hearing upon request. After hearing, the examiner shall recommend a final action by the commission.

(6) Subsequent commission action.

(A) A permit for saltwater or other oil and gas waste disposal may be modified, suspended, or terminated by the commission for just cause after notice and opportunity for hearing, if:

(i) a material change of conditions occurs in the operation or completion of the disposal well, or there are material changes in the information originally furnished;

(ii) freshwater is likely to be polluted as a result of continued operation of the well;

(iii) there are substantial violations of the terms and provisions of the permit or of commission rules;

(iv) the applicant has misrepresented any material facts during the permit issuance process;

(v) injected fluids are escaping from the permitted disposal zone; or

(vi) waste of oil, gas, or geothermal resources is occurring or is likely to occur as a result of the permitted operations.

(B) A disposal well permit may be transferred from one operator to another operator provided that the commission's delegate does not notify the present permit holder of an objection to the transfer prior to the date the lease is transferred on Commission records.

(C) Voluntary permit suspension.

(i) An operator may apply to temporarily suspend its injection authority by filing a written request for permit suspension with the commission in Austin, and attaching to the written request the results of an MIT test performed during the previous three-month period in accordance with the provisions of paragraph (12)(D) of this section. The provisions of this subparagraph shall not apply to any well that is permitted as a commercial disposal well.

(ii) The commission or its delegate may grant the permit suspension upon determining that the results of the MIT test submitted under clause (i) of this subparagraph indicate that the well meets the performance standards of paragraph (12)(D) of this section.

(iii) During the period of permit suspension, the operator shall not use the well for injection or disposal purposes.

(iv) During the period of permit suspension, the operator shall comply with all applicable well testing requirements of §3.14 of this title (relating to plugging, and commonly referred to as Statewide Rule 14) but need not perform the MIT test that would otherwise be required under the provisions of paragraph (12)(D) of this section or the permit. Further, during the period of permit suspension, the provisions of paragraph (11)(A)-(C) of this section shall not apply.

(v) (v) The operator may reinstate injection authority under a suspended permit by filing a written notification with the commission in Austin. The written notification shall be accompanied by an MIT test performed during the three-month period prior to the date notice of reinstatement is filed. The MIT test shall have been performed in accordance with the provisions and standards of paragraph (12)(D) of this section.

(7) Area of Review.

(A) Except as otherwise provided in this paragraph, the applicant shall review the date of public record for wells that penetrate the proposed disposal zone within a 1/4 mile radius of the proposed disposal well to determine if all abandoned wells have been plugged in a manner that will prevent the movement of fluids from the disposal zone into freshwater strata. The applicant shall identify in the application any wells which appear from such review of public records to be unplugged or improperly plugged and any other unplugged or improperly plugged wells of which the applicant has actual knowledge.

(B) The commission or its delegate may grant a variance from the area-of-review requirements of subparagraph (A) of this paragraph upon proof that the variance will not result in a material increase in the risk of fluid movement into freshwater strata or to the surface. Such a variance may be granted for an area defined both vertically and laterally (such as a field) or for an individual well. An application for an areal variance need not be filed in conjunction with an individual permit application or application for permit amendment. Factors that may be considered by the commission or its delegate in granting a variance include:

(i) the area affected by pressure increases resulting from injection operations;

(ii) the presence of local geological conditions that preclude movement of fluid that could endanger freshwater strata or the surface; or

(iii) other compelling evidence that the variance will not result in a material increase in the risk of fluid movement into freshwater strata or to the surface.

(C) Persons applying for a variance from the area-of-review requirements of subparagraph (A) of this paragraph on the basis of factors set out in subparagraph (B)(ii) or (iii) of this paragraph for an individual well shall provide notice of the application to those persons given notice under the provisions of paragraph (5)(A) of this subsection. The provisions of paragraph (5)(D) and (E) shall apply in the case of an application for a variance from the area-of-review requirements for an individual well.

(D) Notice of an application for an areal variance from the area-of-review requirements under subparagraph (A) of this paragraph shall be given on or before the date the application is filed with the commission:

(i) by publication once in a newspaper having general circulation in each county, or portion thereof, where the variance would apply. Such notice shall be in a form approved by the commission or its delegate prior to publication and must be at least three inches by five inches in size. The notice shall state that protests to the application may be filed with the commission during the 15-day period following the date of publication. The notice shall appear in a section of the newspaper containing state or local news items;

(ii) by mailing or delivering a copy of the application, along with a statement that any protest to the application should be filed with the commission within 15 days of the date of the application is filed with the commission, to the following:

(I) the manager of each underground water conservation district(s) in which the variance would apply, if any;

(II) the city clerk or other appropriate official of each incorporated city in which the variance would apply, if any;

(III) the county clerk of each county in which the variance would apply; and

(IV) any other person or persons that the commission or its delegate determine should receive notice of the application.

(E) If a protest to an application for an areal variance is made to the commission by an affected person, local government, underground water conservation district, or other state agency within 15 days of receipt of the application or of publication, whichever is later, or if the commission's delegate determines that a hearing on the application is in the public interest, then a hearing will be held on the application after the commission provides notice of the hearing to all local governments, underground water conservation districts, state agencies, or other persons, who express an interest, in writing, in the application. If no protest from an affected person is received by the commission, the commission's delegate may administratively approve the application. If the application is denied administratively, the person(s) filing the application shall have a right to hearing upon request. After hearing, the examiner shall recommend a final action by the commission.

(F) An areal variance granted under the provisions of this paragraph may be modified, terminated, or suspended by the commission after notice and opportunity for hearing is provided to each person shown on commission records to operate an oil or gas lease in the area in which the proposed modification, termination, or suspension would apply. If a hearing on a proposal to modify, terminate, or suspend an areal variance is held, any applications filed subsequent to the date notice of hearing is given must include the area-of-review information required under subparagraph (A) of this paragraph pending issuance of a final order.

(8) Casing. Disposal wells shall be cased and the casing cemented in compliance with §3.13 of this title (relating to Casing, Cementing, Drilling, and Completion Requirements) in such a manner that the injected fluids will not endanger oil, gas, geothermal resources, or freshwater resources.

(9) Special equipment.

(A) Tubing and packer. Wells drilled or converted for disposal shall be equipped with tubing set on a mechanical packer. Packers shall be set no higher than 100 feet above the top of the permitted interval. For purposes of this section, the term "tubing" refers to a string of pipe through which injection may occur and which is neither wholly nor partially cemented in place. A string of pipe that is wholly or partially cemented in place is considered casing for purposes of this section.

(B) Pressure valve. The wellhead shall be equipped with a pressure observation valve on the tubing and for each annulus of the well.

(C) Exceptions. The director may grant an exception to any provision of this paragraph upon proof of good cause. If the director denies an exception, the operator shall have a right to a hearing upon request. After hearing, the examiner shall recommend a final action by the commission.

(10) Well record. Within 30 days after the completion or conversion of a disposal well, the operator shall file in duplicate in the district office a complete record of the well on the appropriate form which shows the current completion.

(11) Monitoring and reporting.

(A) The operator shall monitor the injection pressure and injection rate of each disposal well on at least a monthly basis.

(B) The results of the monitoring shall be reported annually to the commission on the prescribed from.

(C) All monitoring records shall be retained by the operator for at least five years.

(D) The operator shall report to the appropriate District Office within 24 hours any significant pressure changes or other monitoring data indicating the presence of leaks in the well.

(12) Testing.

(A) Purpose. The mechanical integrity of a disposal well shall be evaluated by conducting pressure tests to determine whether the well tubing, packer, or casing have sufficient mechanical integrity to meet the performance standards of this rule, or by alternative testing methods under subparagraph (E) of this paragraph.

(B) Applicability. Mechanical integrity of each disposal well shall be demonstrated in accordance with provisions of subparagraph (D) and subparagraph (E) of this paragraph prior to initial use. In addition, mechanical integrity shall be tested periodically thereafter as described in subparagraph (C) of this paragraph.

(C) Frequency.

(i) Each disposal well completed with surface casing set and cemented through the entire interval of protected usable-quality water shall be tested for mechanical integrity at least once every five years.

(ii) In addition to testing required under clause (i), each disposal well shall be tested for mechanical integrity after every workover of the well.

(iii) A disposal well that is completed without surface casing set and cemented through the entire interval of protected usable-quality ground water shall be tested at the frequency prescribed in the disposal well permit.

(iv) The commission or its delegate may prescribe a schedule and mail notification to operators to allow for orderly and timely compliance with the requirements in clauses (i) and (ii) of this subparagraph. Such testing schedule shall not apply to a disposal well for which a disposal well permit has been issued but the well has not been drilled or converted to disposal.

(D) Pressure tests.

(i) Test pressure.

(I) The test pressure for wells equipped to dispose through tubing and packer shall equal the maximum authorized injection pressure or 500 psig, whichever is less, but shall be at least 200 psig.

(II) The test pressure for wells that are permitted for disposal through casing shall equal the maximum permitted injection pressure or 200 psig, whichever is greater.

(ii) Pressure stabilization. The test pressure shall stabilize within 10% of the test pressure required in clause (i) of this subparagraph prior to commencement of the test.

(iii) Pressure differential. A pressure differential of at least 200 psig shall be maintained between the test pressure on the tubing-casing annulus and the tubing pressure.

(iv) Test duration. A pressure test shall be conducted for a duration of 30 minutes when the test medium is liquid or for 60 minutes when the test medium is air or gas.

(v) Pressure recorder. Except for tests witnessed by a commission representative or wells permitted for disposal through casing, a pressure recorder shall be used to monitor and record the tubing-casing annulus pressure during the test. The recorder clock shall not exceed 24 hours.

The recorder scale shall be set so that the test pressure is 30 to 70% of full scale, unless otherwise authorized by the commission or its delegate.

(vi) Test fluid.

(I) The tubing-casing annulus fluid used in a pressure test shall be liquid for wells that inject liquid unless the commission or its delegate authorizes the use of a different test fluid for good cause.

(II) The tubing-casing annulus fluid used in a pressure test shall contain no additives that may affect the sensitivity or otherwise reduce the effectiveness of the test.

(vii) Pressure test results. The commission or its delegate will consider, in evaluating the results of a test, the level of pollution risk that loss of well integrity would cause. Factors that may be taken into account in assessing pollution risk include injection pressure, frequency of testing and monitoring, and whether there is sufficient surface casing to cover all zones containing usable-quality water. A pressure test may be rejected by the commission or its delegate after consideration of the following factors:

(I) the degree of pressure change during the test, if any;

(II) the level of risk to usable-quality water if mechanical integrity of the well is lost; and

(III) whether circumstances surrounding the administration of the test make the test inconclusive.

(E) Alternative testing methods.

(i) As an alternative to the testing required in subparagraph (B) of this paragraph, the tubing-casing annulus pressure may be monitored and included on the annual monitoring report required by paragraph (11) of this section, with the authorization of the commission or its delegate and provided that there is no indication of problems with the well. Wells that are approved for tubing-casing annulus monitoring under this paragraph shall be tested in the manner provided under subparagraph (B) of this paragraph at least once every ten years after January 1, 1990.

(ii) The commission or its delegate may grant an exception for viable alternative tests or surveys or may require alternative tests or surveys as a permit condition.

(F) The operator shall notify the appropriate district office at least 48 hours prior to the testing. Testing shall not commence before the end of the 48-hour period unless authorized by the district office.

(G) A complete record of all tests shall be filed in duplicate in the district office on the appropriate form within 30 days after the testing.

(H) In the case of permits issued under this section prior to the effective date of this amendment which require pressure testing more frequently than once every five years, the commission's delegate may, by letter of authorization, reduce the required frequency of pressure tests, provided that such tests are required at least once every three years. The commission shall consider the permit to have been amended to require pressure tests at the frequency specified in the letter of authorization.

(13) Plugging. Disposal wells shall be plugged upon abandonment in accordance with §3.14 of this title (relating to Plugging).

(14) Penalties.

(A) Violations of this section may subject the operator to penalties and remedies specified in the Texas Water Code, Chapter 27, and the Natural Resources Code, Title 3.

(B) The certificate of compliance for any oil, gas, or geothermal resource well may be revoked in the manner provided in §3.68 of this title (relating to Pipeline Connection and Severance) for violation of this section.

RULE §3.14
Plugging

(a) Definitions and application to plug.

(1) The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise:

(A) Active operation--Regular and continuing activities related to the production of oil and gas for which the operator has all necessary permits. In the case of a well that has been inactive for 12 consecutive months or longer and that is not permitted as a disposal or injection well, the well remains inactive for purposes of this section, regardless of any minimal activity, until the well has reported production of at least 10 barrels of oil for oil wells or 100 mcf of gas for gas wells each month for at least three consecutive months.

(B) Bay well--Any well under the jurisdiction of the Commission for which the surface location is either:

(i) located in or on a lake, river, stream, canal, estuary, bayou or other inland navigable waters of the state; or,

(ii) located on state lands seaward of the mean high tide line of the Gulf of Mexico in water of a depth at mean high tide of not more than 100 feet that is sheltered from the direct action of the open seas of the Gulf of Mexico.

(C) Delinquent inactive well--An unplugged well that has had no reported production, disposal, injection, or other permitted activity for a period of greater than 12 months and for which, after notice and opportunity for hearing, the Commission has not extended the plugging deadline.

(D) Funnel viscosity--Viscosity as measured by the Marsh funnel, based on the number of seconds required for 1,000 cubic centimeters of fluid to flow through the funnel.

(E) (E) Good faith claim--A factually supported claim based on a recognized legal theory to a continuing possessory right in a mineral estate, such as evidence of a currently valid oil and gas lease or a recorded deed conveying a fee interest in the mineral estate.

(F) Individual well bond--A bond or letter of credit issued:

(i) on a Commission-approved form;

(ii) by a third party surety, insurance company, or financial institution approved by the Commission; and

(iii) to secure the timely and proper plugging of a specified well and remediation of the wellsite in accordance with Commission rules.

(G) Land well--Any well subject to Commission jurisdiction for which the surface location is not in or on inland or coastal waters.

(H) Offshore well--Any well subject to Commission jurisdiction for which the surface location is on state lands in or on the Gulf of Mexico, that is not a bay well.

(I) Operator designation form--A certificate of transportation authority and compliance or an application to drill, deepen, recomplete, plug back, or reenter which has been completed, signed and filed with the Commission.

(J) Productive horizon--Any stratum known to contain oil, gas, or geothermal resources in producible quantities in the vicinity of an unplugged well.

(K) Reported production--Production of oil or gas, excluding production attributable to well tests, accurately reported to the Commission on a monthly producer's report.

(L) To serve surface notice--To hand deliver a written notice identifying the well to be plugged and the projected date the well will be plugged to the intended recipient at least three days prior to the day of plugging or to mail the notice by first class mail, postage pre-paid, to the last known address of the intended recipient at least seven days prior to the day of plugging.

(M) Unbonded operator--An operator that has a current and active organization report on file with the Commission but that does not have a current individual performance bond, blanket performance bond, letter of credit, or cash deposit as its financial security under §3.78 of this title (relating to Fees, Performance Bonds, and Alternate Forms of Financial Security Required to be Filed (Statewide Rule 78).

(N) Usable quality water strata--All strata determined by the Texas Natural Resource Conservation Commission to contain usable quality water.

(O) Written notice--Notice actually received by the intended recipient in tangible or retrievable form, including notice set out on paper and hand-delivered, facsimile transmissions, and electronic mail transmissions.

(2) The operator shall give the Commission notice of its intention to plug any well or wells drilled for oil, gas, or geothermal resources or for any other purpose over which the Commission has jurisdiction, except those specifically addressed in §3.100(f)(1) of this title (relating to Seismic Holes and Core Holes) (Statewide Rule 100), prior to plugging. The operator shall deliver or transmit the written notice to the district office on the appropriate form.

(3) The operator shall cause the notice of its intention to plug to be delivered to the district office at least five days prior to the beginning of plugging operations. The notice shall set out the proposed plugging procedure as well as the complete casing record. The operator shall not commence the work of plugging the well or wells until the proposed procedure has been approved by the district office. The operator shall not initiate approved plugging operations before the date set out in the notification for the beginning of plugging operations unless authorized by the district director. The operator shall notify the district office at least four hours before commencing plugging operations and proceed with the work as approved. The district director may grant exceptions to the requirements of this paragraph concerning the timing of notices when a workover or drilling rig is already at work on location, ready to commence plugging operations. Operations shall not be suspended prior to plugging the well unless the hole is cased and casing is cemented in place in compliance with Commission rules.

(4) The landowner and the operator may file an application to condition an abandoned well located on the landowner's tract for usable quality water production operations, provided the landowner assumes responsibility for plugging the well and obligates himself, his heirs, successors, and assignees as a condition to the Commission's approval of such application to complete the plugging operations. The application shall be made on the form prescribed by the Commission. In all cases, the operator responsible for plugging the well shall place all cement plugs required by this rule up to the base of the usable quality water strata.

(5) The operator of a well shall serve surface notice on the surface owner of the well site tract, or the resident if the owner is absent, before the scheduled date for beginning the plugging operations. A representative of the surface owner may be present to witness the plugging of the well. Plugging shall not be delayed because of the lack of actual notice to the surface owner or resident if the operator has served surface notice as required by this paragraph. The district director may grant exceptions to the requirements of this paragraph concerning the timing of notices when a workover or drilling rig is already at work on location ready to commence plugging operations.

(b) Commencement of plugging operations and extensions.

(1) The operator shall complete and file in the district office a duly verified plugging record, in duplicate, on the appropriate form within 30 days after plugging operations are completed. A cementing report made by the party cementing the well shall be attached to, or made a part of, the plugging report. If the well the operator is plugging is a dry hole, an electric log status report shall be filed with the plugging record.

(2) Plugging operations on each dry or inactive well shall be commenced within a period of one year after drilling or operations cease and shall proceed with due diligence until completed. Plugging operations on delinquent inactive wells shall be commenced immediately unless the well is restored to active operation. For good cause, a reasonable extension of time in which to start the plugging operations may be granted pursuant to the following procedures.

(A) Wells that have been inactive for less than 36 months.

(i) The Commission or its delegate may administratively grant an extension of up to one year of the deadline for plugging a well that is operated by an unbonded operator and has been inactive, without a return to active operation, for a period of less than 36 months if the following criteria are met:

(I) The well and associated facilities are in compliance with all other laws and Commission rules;

(II) The operator's organization report is current and active;

(III) The operator has, and upon request provides evidence of, a good faith claim to a continuing right to operate the well;

(IV) The operator has paid the proper fee as provided in §3.78 of this title (relating to Fees, Performance Bonds, and Alternative Forms of Financial Security Required To Be Filed) (Statewide Rule 78);

(V) The operator has tested the well in accordance with the provisions of subparagraph (E) of this section and files with its application proof of either:

(-a-) a fluid level test conducted within 90 days prior to the application for a plugging extension demonstrating that any fluid in the wellbore is at least 250 feet below the base of the deepest usable quality water strata; or,

(-b-) a hydraulic pressure test conducted during the period the well has been inactive demonstrating the mechanical integrity of the well; and,

(VI) The requested plugging extension will not extend beyond the thirty-sixth month of inactivity.

(ii) A plugging extension granted under this subparagraph may not extend the period of inactivity beyond 36 months.

(B) Wells that have been inactive for 36 months or longer.

(i) The Commission or its delegate may administratively grant an extension of up to one year of the deadline for plugging a well that is operated by an unbonded operator and has been inactive, without a return to active operation, for a period of 36 months or longer if the criteria set out in subclauses (I)-(IV) of subsection (b)(2)(A)(i) of this section are met, and, in addition:

(I) The operator has tested the well in accordance with the provisions of subparagraph (E) of this paragraph and files with its application proof of either:

(-a-) a fluid level test conducted within 90 days prior to the application for a plugging extension demonstrating that any fluid in the wellbore is at least 250 feet below the base of the deepest usable quality water strata, or,

(-b-) a hydraulic pressure test conducted during the period the well has been inactive and not more than four years prior to the date of application demonstrating the mechanical integrity of the well; and,

(II) The operator files an individual well bond in the amount provided for in §3.78(m) of this title (relating to Fees, Performance Bonds, and Alternative Forms of Financial Security Required To Be Filed) (Statewide Rule 78).

(ii) An operator may rebut the presumed estimated plugging costs for aspecific well for which a plugging extension is sought at hearing by clear and convincing evidence establishing a higher or lower prospective plugging cost for the well. The operator, Commission staff, or any owner of the surface or mineral estate on which the well is located may initiate a hearing on the prospective plugging cost for a well for the purpose of setting the amount of an individual well bond by filing a request for hearing.

(C) Plugging of inactive wells operated by bonded operators. An operator that maintains valid, Commission-approved financial security in the form of an individual performance bond, blanket performance bond, letter of credit, or cash deposit as provided in §3.78 of this title (relating to Fees, Performance Bonds, and Alternate Forms of Financial Security Required to be Filed) (Statewide Rule 78) will be granted a one-year plugging extension for each well it operates that has been inactive for 12 months or more at the time its annual organizational report is approved by the Commission if the following criteria are met:

(i) The well and associated facilities are in compliance with all laws and Commission rules; and,

(ii) The operator has, and upon request provides evidence of, a good faith claim to a continuing right to operate the well.

(D) Revocation or denial of plugging extension.

(i) The Commission or its delegate may revoke a plugging extension if the operator of the well that is the subject of the extension fails to maintain the well and all associated facilities in compliance with Commission rules; fails to maintain a current and accurate organizational report on file with the Commission; fails to provide the Commission, upon request, with evidence of a continuing good faith claim to operate the well; or fails to obtain or maintain a valid individual well bond or organizational bond or letter of credit as required by this subsection.

(ii) If the Commission or its delegate declines to grant or continue a plugging extension or revokes a previously granted extension, the operator shall either return the well to active operation or, within 30 days, plug the well or request a hearing on the matter.

(E) The operator of any well more than 25 years old that becomes inactive and subject to the provisions of this paragraph and the operator of any well for which a plugging extension is sought under the terms of subparagraph (A) or (B) of this paragraph shall plug or test such well to determine whether the well poses a potential threat of harm to natural resources, including surface and subsurface water, oil and gas.

(i) In general, a fluid level test is a sufficient test for purposes of this subparagraph. The operator must give the district office written notice specifying the date and approximate time it intends to conduct the fluid level test at least 48 hours prior to conducting the test; however, upon a showing of undue hardship, the district office may grant a written waiver or reduction of the notice requirement for a specific well test. The Commission or its delegate may require alternate methods of testing if the Commission deems it necessary to ensure the well does not pose a potential threat of harm to natural resources. Alternate methods of testing may be approved by the Commission or its delegate by written application and upon a showing that such a test will provide information sufficient to determine that the well does not pose a threat to natural resources.

(ii) No test other than a fluid level test shall be acceptable without prior approval from the district office. The district office shall be notified at least 48 hours before any test other than a fluid level test is conducted. Mechanical integrity test results shall be filed with the district office and fluid level test results shall be filed with the Commission in Austin. Test results shall be filed on a Commission-approved form, within 30 days of the completion of the test. Upon request, the operator shall file the actual test data for any mechanical integrity or fluid level test that it has conducted.

(iii) Notwithstanding the provisions of clause (ii) of this subparagraph, a hydraulic pressure test may be conducted without prior approval from the district office, provided that the operator gives the district office written notice specifying the date and approximate time for the test at least 48 hours prior to the time the test will be conducted, the production casing is tested to a depth of at least 250 feet below the base of usable quality water strata, or 100 feet below the top of cement behind the production casing, whichever is deeper, and the minimum test pressure is greater than or equal to 250 psig for a period of at least 30 minutes.

(iv) If the operator performs a hydraulic pressure test in accordance with the provisions of clause (iii) of this subparagraph, the well shall be exempt from further testing for five years from the date of the test, except to the extent compliance with paragraph (2) of subsection (b) of this section requires more frequent testing. Further, the Commission or its delegate may require the operator to perform testing more frequently to ensure that the well does not pose a threat of harm to natural resources. The Commission or its delegate may approve less frequent well tests under this subparagraph upon written request and for good cause shown provided that less frequent testing will not increase the threat of harm to natural resources.

(v) Wells that are returned to continuous production, as evidenced by three consecutive months of reported production of at least 10 barrels of oil or 100 mcf of gas per month, need not be tested.

(3) Transfer of operatorship. A transfer of operatorship submitted for any well or lease will not be approved unless the operator acquiring the well or lease has on file with the Commission financial security as provided in §3.78 of this title (relating to Fees, Performance Bonds, and Alternate Forms of Financial Security Required to be Filed) (Statewide Rule 78).

(4) The Commission may plug or replug any dry or inactive well as follows:

(A) After notice and hearing, if the well is causing or is likely to cause the pollution of surface or subsurface water or if oil or gas is leaking from the well, and:

(i) Neither the operator nor any other entity responsible for plugging the well can be found; or

(ii) Neither the operator nor any other entity responsible for plugging the well has assets with which to plug the well.

(B) Without a hearing if the well is a delinquent inactive well and:

(i) the Commission has sent notice of its intention to plug the well as required by §89.043(c) of the Texas Natural Resources Code; and

(ii) the operator did not request a hearing within the period (not less than 10 days after receipt) specified in the notice.

(C) Without notice or hearing, if:

(i) The Commission has issued a final order requiring that the operator plug the well and the order has not been complied with; or

(ii) The well poses an immediate threat of pollution of surface or subsurface waters or of injury to the public health and the operator has failed to timely remediate the problem.

(5) The Commission may seek reimbursement from the operator and any other entity responsible for plugging the well for state funds expended pursuant to paragraph (4) of this subsection.

(c) Designated operator responsible for proper plugging.

(1) The entity designated as the operator of a well specifically identified on the most recent Commission-approved operator designation form filed on or after September 1, 1997, is responsible for properly plugging the well in accordance with this section and all other applicable Commission rules and regulations concerning plugging of wells.

(2) As to any well for which the most recent Commission-approved operator designation form was filed prior to September 1, 1997, the entity designated as operator on that form is presumed to be the entity responsible for the physical operation and control of the well and to be the entity responsible for properly plugging the well in accordance with this section and all other applicable Commission rules and regulations concerning plugging of wells. The presumption of responsibility may be rebutted only at a hearing called for the purpose of determining plugging responsibility.

(d) General plugging requirements.

(1) Wells shall be plugged to insure that all formations bearing usable quality water, oil, gas, or geothermal resources are protected. All cementing operations during plugging shall be performed under the direct supervision of the operator or his authorized representative, who shall not be an employee of the service or cementing company hired to plug the well. Direct supervision means supervision at the well site during the plugging operations. The operator and the cementer are both responsible for complying with the general plugging requirements of this subsection and for plugging the well in conformity with the procedure set forth in the approved notice of intention to plug and abandon for the well being plugged. The operator and cementer may each be assessed administrative penalties for failure to comply with the general plugging requirements of this subsection or for failure to plug the well in conformity with the approved notice of intention to plug and abandon the well.

(2) Cement plugs shall be set to isolate each productive horizon and usable quality water strata.

(3) Cement plugs shall be placed by the circulation or squeeze method through tubing or drill pipe. Cement plugs shall be placed by other methods only upon written request with the written approval of the district director or the director's delegate.

(4) All cement for plugging shall be an approved API oil well cement without volume extenders and shall be mixed in accordance with API standards. Slurry weights shall be reported on the cementing report. The district director or the director's delegate may require that specific cement compositions be used in special situations; for example, when high temperature, salt section, or highly corrosive sections are present.

(5) Operators shall use only cementers approved by the assistant director of well plugging or the assistant director's delegate, except when plugging is conducted in accordance with subparagraph (B)(ii) of this paragraph or paragraph (6) of this subsection. Cementing companies, service companies, or operators may apply for designation as approved cementers. Approval will be granted on a showing by the applicant of the ability to mix and pump cement in compliance with this rule. An approved cementer is authorized to conduct plugging operations in accordance with Commission rules in each Commission district.

(A) A cementing company, service company, or operator seeking designation as an approved cementer shall file a request in writing with the district director of the district in which it proposes to conduct its initial plugging operations. The request shall contain the following information:

(i) the name of the organization as shown on its most recent approved organizational report;

(ii) a list of qualifications including personnel who will supervise mixing and pumping operations;

(iii) length of time the organization has been in the business of cementing oil and gas wells;

(iv) an inventory of the type of equipment to be used to mix and pump cement; and

(v) a statement certifying that the organization will comply with all Commission rules.

(B) No request for designation as an approved cementer will be approved until after the district director or the director's delegate has:

(i) inspected all equipment to be used for mixing and pumping cement; and

(ii) witnessed at least one plugging operation to determine if the cementing company, service company, or operator can properly mix and pump cement to the specifications required by this rule.

(C) The district director or the director's delegate shall file a letter with the assistant director of well plugging recommending that the application to be designated as an approved cementer be approved or denied. If the district director or the director's delegate does not recommend approval, or the assistant director of well plugging or the assistant director's delegate denies the application, the applicant may request a hearing on its application.

(D) Designation as an approved cementer may be suspended or revoked for violations of Commission rules. The designation may be revoked or suspended administratively by the assistant director of well plugging for violations of Commission rules if:

(i) the cementer has been given written notice by personal service or by registered or certified mail informing the cementer of the proposed action, the facts or conduct alleged to warrant the proposed action, and of its right to request a hearing within 10 days to demonstrate compliance with Commission rules and all requirements for retention of designation as an approved cementer; and

(ii) the cementer did not file a written request for a hearing within 10 days of receipt of the notice.

(6) An operator may request administrative authority to plug its own wells without being an approved cementer. An operator seeking such authority shall file a written request with the district director and demonstrate its ability to mix and pump cement in compliance with this subsection. The district director or the director's delegate will determine whether such a request warrants approval. If the district director or the director's delegate refuses to administratively approve this request, the operator may request a hearing on its request.

(7) The district director may require additional cement plugs to cover and contain any productive horizon or to separate any water stratum from any other water stratum if the water qualities or hydrostatic pressures differ sufficiently to justify separation. The tagging and/or pressure testing of any such plugs, or any other plugs, and respotting may be required if necessary to insure that the well does not pose a potential threat of harm to natural resources.

(8) For onshore or inland wells, a 10-foot cement plug shall be placed in the top of the well, and casing shall be cut off three feet below the ground surface.

(9) Mud-laden fluid of at least 9-1/2 pounds per gallon with a minimum funnel viscosity of 40 seconds shall be placed in all portions of the well not filled with cement. The hole shall be in static condition at the time the cement plugs are placed. The district director may grant exceptions to the requirements of this paragraph if a deviation from the prescribed minimums for fluid weight or viscosity is necessary to insure that the well does not pose a potential threat of harm to natural resources.

(10) Non-drillable material that would hamper or prevent reentry of a well shall not be placed in any wellbore during plugging operations, except in the case of a well plugged and abandoned under the provisions of §3.35 or §3.94(e) of this title (relating to Procedures for Identification and Control of Wellbores in Which Certain Logging Tools Have Been Abandoned (Statewide Rule 35); and Disposal of Oil and Gas NORM Waste (Statewide Rule 94), respectively). Pipe and unretrievable junk shall not be cemented in the hole during plugging operations without prior approval by the district director.

(11) All cement plugs, except the top plug, shall have sufficient slurry volume to fill 100 feet of hole, plus 10% for each 1,000 feet of depth from the ground surface to the bottom of the plug.

(12) The operator shall fill the rathole, mouse hole, and cellar, and shall empty all tanks, vessels, related piping and flowlines that will not be actively used in the continuing operation of the lease within 120 days after plugging work is completed. Within the same 120 day period, the operator shall remove all such tanks, vessels, related surface piping, and all subsurface piping that is less than three feet beneath the ground surface, remove all loose junk and trash from the location, and contour the location to discourage pooling of surface water at or around the facility site. The operator shall close all pits in accordance with the provisions of §3.8 of this title (relating to Water Protection (Statewide Rule 8)). The district director may grant a reasonable extension of time of not more than an additional 120 days for the removal of tanks, vessels and related piping.

(e) Plugging requirements for wells with surface casing.

(1) When insufficient surface casing is set to protect all usable quality water strata and such usable quality water strata are exposed to the wellbore when production or intermediate casing is pulled from the well or as a result of such casing not being run, a cement plug shall be placed from 50 feet below the base of the deepest usable quality water stratum to 50 feet above the top of the stratum. This plug shall be evidenced by tagging with tubing or drill pipe. The plug must be respotted if it has not been properly placed. In addition, a cement plug must be set across the shoe of the surface casing. This plug must be a minimum of 100 feet in length and shall extend at least 50 feet above and below the shoe.

(2) When sufficient surface casing has been set to protect all usable quality water strata, a cement plug shall be placed across the shoe of the surface casing. This plug shall be a minimum of 100 feet in length and shall extend at least 50 feet above the shoe and at least 50 feet below the shoe.

(3) If surface casing has been set deeper than 200 feet below the base of the deepest usable quality water stratum, an additional cement plug shall be placed inside the surface casing across the base of the deepest usable quality water stratum. This plug

shall be a minimum of 100 feet in length and shall extend from 50 feet below the base of the deepest usable quality water stratum to 50 feet above the top of the stratum.

(f) Plugging requirements for wells with intermediate casing.

(1) For wells in which the intermediate casing has been cemented through all usable quality water strata and all productive horizons, a cement plug meeting the requirements of subsection (d)(11) of this section shall be placed inside the casing and centered opposite the base of the deepest usable quality water stratum, but extend no less than 50 feet above and below the stratum.

(2) For wells in which intermediate casing is not cemented through all usable quality water strata and all productive horizons, and if the casing will not be pulled, the intermediate casing shall be perforated at the required depths to place cement outside of the casing by squeeze cementing through casing perforations.

(g) Plugging requirements for wells with production casing.

(1) For wells in which the production casing has been cemented through all usable quality water strata and all productive horizons, a cement plug meeting the requirements of subsection (d)(11) of this section shall be placed inside the casing and centered opposite the base of the deepest usable quality water stratum and across any multi-stage cementing tool.

(2) For wells in which the production casing has not been cemented through all usable quality water strata and all productive horizons and if the casing will not be pulled, the production casing shall be perforated at the required depths to place cement outside of the casing by squeeze cementing through casing perforations.

(3) The district director may approve a cast iron bridge plug to be placed immediately above each perforated interval, provided at least 20 feet of cement is placed on top of each bridge plug. A bridge plug shall not be set in any well at a depth where the pressure or temperature exceeds the ratings recommended by the bridge plug manufacturer.

(h) Plugging requirements for well with screen or liner.

(1) If practical, the screen or liner shall be removed from the well.

(2) If the screen or liner is not removed, a cement plug in accordance with subsection (d)(11) of this section shall be placed at the top of the liner.

(i) Plugging requirements for wells without production casing and open-hole completions.

(1) Any productive horizon or any formation in which a pressure or formation water problem is known to exist shall be isolated by cement plugs centered at the top and bottom of the formation. Each cement plug shall have sufficient slurry volume to fill a calculated height as specified in subsection (d)(11) of this section.

(2) If the gross thickness of any such formation is less than 100 feet, the tubing or drill pipe shall be suspended 50 feet below the base of the formation. Sufficient slurry volume shall be pumped to fill the calculated height from the bottom of the tubing or drill pipe up to a point at least 50 feet above the top of the formation, plus 10% for each 1,000 feet of depth from the ground surface to the bottom of the plug.

(j) The district director shall review and approve the notification of intention to plug in a manner so as to accomplish the purposes of this section. The district director may approve, modify, or reject the operator's notification of intention to plug. If the proposal is modified or rejected, the operator may request a review by the director of field operations. If the proposal is not administratively approved, the operator may request a hearing on the matter. After hearing, the examiner shall recommend final action by the Commission.

(k) Plugging horizontal drainhole wells. All plugs in horizontal drainhole wells shall be set in accordance with subsection (d)(11) of this section. The productive horizon isolation plug shall be set from a depth 50 feet below the top of the productive horizon to a depth either 50 feet above the top of the productive horizon, or 50 feet above the production casing shoe if the production casing is set above the top of the productive horizon. If the production casing shoe is set below the top of the productive horizon, then the productive horizon isolation plug shall be set from a depth 50 feet below the production casing shoe to a depth that is 50 feet above the top of the productive horizon. In accordance with subsection (d)(7) of this section, the Commission or its delegate may require additional plugs.

RULE §3.46
Fluid Injection into Productive Reservoirs

(a) Permit required. Any person who engages in fluid injection operations in reservoirs productive of oil, gas, or geothermal resources must obtain a permit from the commission. Permits may be issued when the injection will not endanger oil, gas, or geothermal resources or cause the pollution of freshwater strata unproductive of oil, gas, or geothermal resources. Permits from the commission issued before the effective date of this section shall continue in effect until revoked, modified, or suspended by the commission.

(b) Filing of application.

(1) Application. An application to conduct fluid injection operations in a reservoir productive of oil, gas, or geothermal resources shall be filed in Austin on the form prescribed by the commission accompanied by the prescribed fee. On the same date,

one copy shall be filed with the appropriate district office. The form shall be executed by a party having knowledge of the facts entered on the form. The applicant shall file the freshwater injection data form if fresh water is to be injected.

(2) Commercial disposal well. An applicant for a permit to dispose of oil and gas waste in a commercial disposal well shall clearly indicate on the application and in the notice of application that the application is for a commercial disposal well permit. For the purposes of this rule, "commercial disposal well" means a well whose owner or operator receives compensation from others for the disposal of oil field fluids or oil and gas wastes that are wholly or partially trucked or hauled to the well, and the primary business purpose for the well is to provide these services for compensation.

(c) Notice and opportunity for hearing.

(1) The applicant shall give notice by mailing or delivering a copy of the application to affected persons who include the owner of record of the surface tract on which the well is located; each commission-designated operator of any well located within one half mile of the proposed injection well; the county clerk of the county in which the well is located; and the city clerk or other appropriate city official of any city where the well is located within the corporate limits of the city, on or before the date the application is mailed to or filed with the commission. For the purposes of this section, the term "of record" means recorded in the real property or probate records of the county in which the property is located.

(2) In addition to the requirements of subsection (c)(1), a commercial disposal well permit applicant shall give notice to owners of record of each surface tract that adjoins the proposed injection tract by mailing or delivering a copy of the application to each such surface owner.

(3) If, in connection with a particular application, the commission or its delegate determines that another class of persons should receive notice of the application, the commission or its delegate may require the applicant to mail or deliver a copy of the application to members of that class. Such classes of persons could include adjacent surface owners or underground water conservation districts.

(4) In order to give notice to other local governments, interested, or affected persons, notice of the application shall be published once by the applicant in a newspaper of general circulation for the county where the well will be located in a form approved by the commission or its delegate. The applicant shall file with the commission in Austin proof of publication prior to the hearing or administrative approval.

(5) Protested applications:

(A) If a protest from an affected person or local government is made to the commission within 15 days of receipt of the application or of publication, whichever is later, or if the commission or its delegate determines that a hearing is in the public interest, then a hearing will be held on the application after the commission provides notice of hearing to all affected persons, local governments, or other persons, who express an interest, in writing, in the application.

(B) For purposes of this section, "affected person" means 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.

(6) If no protest from an affected person is received by the commission, the commission's delegate may administratively approve the application. If the commission's delegate denies administrative approval, the applicant shall have a right to a hearing upon request. After hearing, the examiner shall recommend a final action by the commission.

(d) Subsequent commission action.\

(1) An injection well permit may be modified, suspended, or terminated by the commission for just cause after notice and opportunity for hearing, if:

(A) a material change of conditions occurs in the operation or completion of the injection well, or there are material changes in the information originally furnished;

(B) fresh water is likely to be polluted as a result of continued operation of the well;

(C) there are substantial violations of the terms and provisions of the permit or of commission rules;

(D) the applicant has misrepresented any material facts during the permit issuance process;

(E) injected fluids are escaping from the permitted injection zone; or

(F) waste of oil, gas, or geothermal resources is occurring or is likely to occur as a result of the permitted operations.

(2) An injection well permit may be transferred from one operator to another operator provided that the commission's delegate does not notify the present permit holder of an objection to the transfer prior to the date the lease is transferred on commission records.

(3) Voluntary permit suspension.

(A) An operator may apply to temporarily suspend its injection authority by filing a written request for permit suspension with the commission in Austin, and attaching to the written request the results of an MIT test performed during the previous three-month period in accordance with the provisions of subsection (j)(4) of this section. The provisions of this paragraph shall not apply to any well that is permitted as a commercial injection well.

(B) The commission or its delegate may grant the permit suspension upon determining that the results of the MIT test submitted under subparagraph (A) of this paragraph indicate that the well meets the performance standards of subsection (j)(4) of this section.

(C) During the period of permit suspension, the operator shall not use the well for injection or disposal purposes.

(D) During the period of permit suspension, the operator shall comply with all applicable well testing requirements of §3.14 of this title (relating to plugging, and commonly referred to as Statewide Rule 14) but need not perform the MIT test that would otherwise be required under the provisions of subsection (j)(4) of this section or the permit. Further, during the period of permit suspension, the provisions of subsection (i)(1)-(3) of this section shall not apply.

(E) The operator may reinstate injection authority under a suspended permit by filing a written notification with the commission in Austin. The written notification shall be accompanied by an MIT test performed during the three-month period prior to the date notice of reinstatement is filed. The MIT test shall have been performed in accordance with the provisions and standards of subsection (j)(4) of this section.

(e) Area of Review.

(1) Except as otherwise provided in this subsection, the applicant shall review the data of public record for wells that penetrate the proposed disposal zone within a 1/4 mile radius of the proposed disposal well to determine if all abandoned wells have been plugged in a manner that will prevent the movement of fluids from the disposal zone into freshwater strata. The applicant shall identify in the application any wells which appear from such review of public records to be unplugged or improperly plugged and any other unplugged or improperly plugged wells of which the applicant has actual knowledge.

(2) The commission or its delegate may grant a variance from the area-of-review requirements of paragraph (1) of this subsection upon proof that the variance will not result in a material increase in the risk of fluid movement into freshwater strata or to the surface. Such a variance may be granted for an area defined both vertically and laterally (such as a field) or for an individual well. An application for an areal variance need not be filed in conjunction with an individual permit application or

application for permit amendment. Factors that may be considered by the commission or its delegate in granting a variance include:

(A) the area affected by pressure increases resulting from injection operations;

(B) the presence of local geological conditions that preclude movement of fluid that could endanger freshwater strata or the surface; or

(C) other compelling evidence that the variance will not result in a material increase in the risk of fluid movement into freshwater strata or to the surface.

(3) Persons applying for a variance from the area-of-review requirements of paragraph (1) of this subsection on the basis of factors set out in paragraph (2)(B) or (C) of this subsection for an individual well shall provide notice of the application to those persons given notice under the provisions of subsection (c)(1) of this section. The provisions of subsection (c) of this section shall apply in the case of an application for a variance from the area-of-review requirements for an individual well.

(4) Notice of an application for an areal variance from the area-of-review requirements under paragraph (1) of this subsection shall be given on or before the date the application is filed with the commission:

(A) by publication once in a newspaper having general circulation in each county, or portion thereof, where the variance would apply. Such notice shall be in a form approved by the commission or its delegate prior to publication and must be at least three inches by five inches in size. The notice shall state that protests to the application may be filed with the commission during the 15-day period following the date of publication. The notice shall appear in a section of the newspaper containing state or local news items;

(B) by mailing or delivering a copy of the application, along with a statement that any protest to the application should be filed with the commission within 15 days of the date the application is filed with the commission, to the following:

(i) the manager of each underground water conservation district in which the variance would apply, if any;

(ii) the city clerk or other appropriate official of each incorporated city in which the variance would apply, if any;

(iii) the county clerk of each county in which the variance would apply; and

(iv) any other person or persons that the commission or its delegate determines should receive notice of the application.

(5) If a protest to an application for an areal variance is made to the commission by an affected person, local government, underground water conservation district, or other state agency within 15 days of receipt of the application or of publication, whichever is later, or if the commission's delegate determines that a hearing on the application is in the public interest, then a hearing will be held on the application after the commission provides notice of the hearing to all local governments, underground water conservation districts, state agencies, or other persons, who express an interest, in writing, in the application. If no protest from an affected person is received by the commission, the commission's delegate may administratively approve the application. If the application is denied administratively, the person(s) filing the application shall have a right to hearing upon request. After hearing, the examiner shall recommend a final action by the commission.

(6) An areal variance granted under the provisions of this subsection may be modified, terminated, or suspended by the commission after notice and opportunity for hearing is provided to each person shown on commission records to operate an oil or gas lease in the area in which the proposed modification, termination, or suspension would apply. If a hearing on a proposal to modify, terminate, or suspend an areal variance is held, any applications filed subsequent to the date notice of hearing is given must include the area-of-review information required under paragraph (1) of this subsection pending issuance of a final order.

(f) Casing. Injection wells shall be cased and the casing cemented in compliance with §3.13 of this title (relating to Casing, Cementing, Drilling, and Completion Requirements) in such a manner that the injected fluids will not endanger oil, gas, or geothermal resources and will not endanger freshwater formations not productive of oil, gas, or geothermal resources.

(g) Special equipment.

(1) Tubing and packer. Wells drilled or converted for injection shall be equipped with tubing set on a mechanical packer. Packers shall be set no higher than 200 feet below the known top of cement behind the long string casing but in no case higher than 150 feet below the base of usable quality water. For purposes of this section, the term "tubing" refers to a string of pipe through which injection may occur and which is neither wholly nor partially cemented in place. A string of pipe that is wholly or partially cemented in place is considered casing for purposes of this section.

(2) Pressure valve. The wellhead shall be equipped with a pressure observation valve on the tubing and for each annulus of the well.

(3) Exceptions. The commission or its delegate may grant an exception to any provision of this paragraph upon proof of good cause. If the commission or its delegate denies an exception, the operator shall have a right to a hearing upon request. After hearing, the examiner shall recommend a final action by the commission.

(h) Well record. Within 30 days after the completion or conversion of an injection well, the operator shall file in duplicate in the district office a complete record of the well on the appropriate form which shows the current completion.

(i) Monitoring and reporting.

(1) The operator shall monitor the injection pressure and injection rate of each injection well on at least a monthly basis.

(2) The results of the monitoring shall be reported annually to the commission on the prescribed form.

(3) All monitoring records shall be retained by the operator for at least five years.

(4) The operator shall report to the appropriate District Office within 24 hours any significant pressure changes or other monitoring data indicating the presence of leaks in the well.

(j) Testing.

(1) Purpose. The mechanical integrity of an injection well shall be evaluated by conducting pressure tests to determine whether the well tubing, packer, or casing have sufficient mechanical integrity to meet the performance standards of this rule, or by alternative testing methods under paragraph (5) of this subsection.

(2) Applicability. Mechanical integrity of each injection well shall be demonstrated in accordance with provisions of paragraphs (4) and (5) of this subsection prior to initial use. In addition, mechanical integrity shall be tested periodically thereafter as described in paragraph (3) of this subsection.

(3) Frequency.

(A) Each injection well completed with surface casing set and cemented through the entire interval of protected usable-quality water shall be tested for mechanical integrity at least once every five years.

(B) In addition to testing required under subparagraph (A), each injection well shall be tested for mechanical integrity after every workover of the well.

(C) An injection well that is completed without surface casing set and cemented through the entire interval of protected usable-quality ground water shall be tested at the frequency prescribed in the injection permit.

(D) The commission or its delegate may prescribe a schedule and mail notification to operators to allow for orderly and timely compliance with the requirements in subparagraph (A) and subparagraph (B) of this paragraph. Such testing schedule shall not apply to an injection well for which an injection well permit has been issued but the well has not been drilled or converted to injection.

(4) Pressure tests.

(A) Test pressure.

(i) The test pressure for wells equipped to inject through tubing and packer shall equal the maximum authorized injection pressure or 500 psig, whichever is less, but shall be at least 200 psig.

(ii) The test pressure for wells that are permitted for injection through casing shall equal the maximum permitted injection pressure or 200 psig, whichever is greater.

(B) Pressure stabilization. The test pressure shall stabilize within 10% of the test pressure required in subparagraph (A) of this paragraph prior to commencement of the test.

(C) Pressure differential. A pressure differential of at least 200 psig shall be maintained between the test pressure on the tubing-casing annulus and the tubing pressure.

(D) Test duration. A pressure test shall be conducted for a duration of 30 minutes when the test medium is liquid or for 60 minutes when the test medium is air or gas.

(E) Pressure recorder. Except for tests witnessed by a commission representative or wells permitted for injection through casing, a pressure recorder shall be used to monitor and record the tubing-casing annulus pressure during the test. The recorder clock shall not exceed 24 hours. The recorder scale shall be set so that the test pressure is 30 to 70% of full scale, unless otherwise authorized by the commission or its delegate.

(F) Test fluid.

(i) The tubing-casing annulus fluid used in a pressure test shall be liquid for wells that inject liquid unless the commission or its delegate authorizes use of a different test fluid for good cause.

(ii) The tubing-casing annulus fluid used in a pressure test shall contain no additives that may affect the sensitivity or otherwise reduce the effectiveness of the test.

(G) Pressure test results. The commission or its delegate will consider, in evaluating the results of a test, the level of pollution risk that loss of well integrity would cause. Factors that may be taken into account in assessing pollution risk include injection pressure, frequency of testing and monitoring, and whether there is sufficient surface casing to cover all zones containing usable-quality water. A pressure test may be rejected by the commission or its delegate after consideration of the following factors:

(i) the degree of pressure change during the test, if any;

(ii) the level of risk to usable-quality water if mechanical integrity of the well is lost; and

(iii) whether circumstances surrounding the administration of the test make the test inconclusive.

(5) Alternative testing methods.

(A) As an alternative to the testing required in paragraph (2) of this subsection, the tubing-casing annulus pressure may be monitored and included on the annual monitoring report required by subsection (i) of this section, with the authorization of the commission or its delegate and provided that there is no indication of problems with the well. Wells that are approved for tubing-casing annulus monitoring under this paragraph shall be tested in the manner provided under paragraph (3) of this subsection at least once every ten years after January 1, 1990.

(B) The commission or its delegate grant an exception for viable alternative tests or surveys or may require alternative tests or surveys as a permit condition.

(6) The operator shall notify the appropriate district office at least 48 hours prior to the testing. Testing shall not commence before the end of the 48-hour period unless authorized by the district office.

(7) A complete record of all tests shall be filed in duplicate in the district office within 30 days after the testing.

(8) In the case of permits issued under this section prior to the effective date of this amendment which require pressure testing more frequently than once every five years, the commission's delegate may, by letter of authorization, reduce the required frequency of pressure tests, provided that such tests are required at least once every three years. The commission shall consider the permit to have been amended to require pressure tests at the frequency specified in the letter of authorization.

(k) Area Permits. A person may apply for an area permit that authorizes injection into new or converted wells located within the area specified in the area permit. For purposes of this subsection, the term "permit area" shall mean the area covered or proposed to be covered by an area permit. Except as specifically provided in this subsection, the provisions of subsections (a)-(j) of this section shall apply in the case of an area permit and all injection wells converted, completed, operated, or maintained in accordance with that permit. Except as otherwise specified in the area permit, once an area permit has been issued, the operator may apply to operate individual wells within the permit area as injection wells as specified in paragraph (3) of this subsection.

(l) An application for an area permit must be accompanied by an application for at least one injection well. The applicant must:

(A) identify the maximum number of injection wells that will be operated within the permit area;

(B) identify the depth(s) of usable-quality water within the permit area, as determined by the Texas Natural Resource Conservation Commission;

(C) for each existing well in the permit area that may be converted to injection under the area permit, provide a wellbore diagram that specifies the casing and liner sizes and depths, packer setting depth, types and volumes of cement, and the cement tops for the well. A single wellbore diagram may be submitted for multiple wells that have the same configuration, provided that each well with that type of configuration is identified on the wellbore diagram and the diagram identifies the deepest cement top for each string of casing among all the wells covered by that diagram.

(D) provide a wellbore diagram(s) showing the type(s) of completion(s) that will be used for injection wells drilled after the date the application for the area permit is filed, including casing and liner sizes and depths and a statement indicating that such wells will be cemented in accordance with the cementing requirements of Rule 13 of this chapter (§3.13 of this title (relating to Casing, Cementing, Drilling, and Completion Requirements));

(E) identify the type or types of fluids that are proposed to be injected into any well within the permit area;

(F) identify the depths from top to bottom of the injection interval throughout the permit area;

(G) specify the maximum surface injection pressure for any well in the permit area covered by the area permit;

(H) specify the maximum amount of fluid that will be injected daily into any individual well within the permit area as well as the maximum cumulative amount of fluid that will be injected daily in the permit area;

(I) in lieu of the area-of-review required under subsection (e) of this section and subject to the area-of-review variance provisions of subsection (e) of this section, review the data of public record for wells that penetrate the proposed injection interval within the permit area and the area 1/4 mile beyond the outer boundary of the permit area to determine if all abandoned wells have been plugged in a manner that will prevent the movement of fluids from the injection interval into freshwater strata. The applicant shall identify in the application the wells which appear from the review of such public records to be unplugged or improperly plugged and any other unplugged or improperly plugged wells of which the applicant has knowledge. The applicant shall also identify in the application the date of plugging of each abandoned well within the permit area and the area 1/4 mile beyond the outer boundary of the permit area; and

(J) furnish a map showing the location of each existing well that may be converted to injection under the area permit and the location of each well that the operator intends, at the time of application, to drill within the permit area for use for injection. The map shall be keyed to identify the configuration of all such wells as described in subparagraphs (C) and (D) of this paragraph.

(2) In lieu of the notice required under subsection (c)(1) of this section, notice of an area permit shall be given by providing a copy of the area permit application to each surface owner of record within the permit area; each commission-designated operator of a well located within one-half mile of the permit area; the county clerk of each county in which all or part of the permit area is located; and the city clerk or other appropriate city official of any incorporated city which is located wholly or partially within the permit area, on or before the date the application is mailed to or filed with the commission. Notice of an application for an area permit shall also be given in accordance with the requirements of subsection (c)(2). If, in connection with a particular application, the commission or its delegate determines that another class of persons, such as adjacent surface owners or an appropriate underground water conservation district, should receive notice of the application, the commission or its delegate may require the applicant to mail or deliver a copy of the application to members of that class.

(3) Once an area permit has been issued and except as otherwise provided in the permit, no notice shall be required when an application for an individual injection well permit for any well covered by the area permit is filed.

(4) Prior to commencement of injection operations in any well within the permit area, the operator shall file an application for an individual well permit with the commission in Austin. The individual well permit application shall include the following:

(A) the well identification and, for a new well, a location plat;

(B) the location of any well drilled within 1/4 mile of the injection well after the date of application for the area permit and the status of any well located within 1/4 mile of the injection well that has been abandoned since the date the area permit was issued, including the plugging date if such well has been plugged;

(C) a description of the well configuration, including casing and liner sizes and setting depths, the type and amount of cement used to cement each casing string, depth of cement tops, and tubing and packer setting depths;

(D) an application fee in the amount of $100 per well; and

(E) any other information required by the area permit.

(5) An individual well permit may be issued by the commission or its delegate in writing or, if no objection to the application is made by the commission or its delegate within 20 days of receipt of the application, the individual well permit shall be deemed issued.

(6) All individual injection wells covered by an area permit must be permitted in accordance with the requirements of this subsection and converted or completed, operated, maintained, and plugged in accordance with the requirements of this section and the area permit.

(l) Gas storage operations. Storage of gas in productive or depleted reservoirs shall be subject to the provisions of §3.96 of this title (relating to Underground Storage of Gas in Productive or Depleted Reservoirs).

(m) Plugging. Injection wells shall be plugged upon abandonment in accordance with §3.14 of this title (relating to Plugging).

(n) Penalties.

(1) Violations of this section may subject the operator to penalties and remedies specified in Title 3 of the Natural Resources Code and any other statutes administered by the commission.

(2) The certificate of compliance for any oil, gas, or geothermal resource well may be revoked in the manner provided in §3.68 of this title (relating to Pipeline Connection and Severance) for violation of this section.

RULE §3.95
Underground Storage of Liquid or Liquefied Hydrocarbons in Salt Formations

(a) Definitions. The following terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Affected person--A person who, as a result of actions proposed in an application for a storage facility permit or for amendment or modification of an existing storage

facility permit, has suffered or may suffer actual injury or economic damage other than as a member of the general public.

(2) Brine string--The uncemented tubing through which highly saline water flows into or out of a hydrocarbon storage well during hydrocarbon withdrawal or injection operations.

(3) Cavern--The storage space created in a salt formation by solution mining.

(4) Commission--The Railroad Commission of Texas.

(5) Emergency shutdown valve--A valve that automatically closes to isolate a hydrocarbon storage well from surface piping in the event of specified conditions that, if uncontrolled, may cause an emergency.

(6) Fire detector--A device capable of detecting the presence of a flame or the heat from a fire.

(7) Fresh water--Water having bacteriological, physical, and chemical properties that make it suitable and feasible for beneficial use for any lawful purpose. For purposes of this section, brine associated with the creation, operation, and maintenance of an underground hydrocarbon storage facility is not considered fresh water.

(8) Hydrocarbon storage well or storage well--A well used for the injection or withdrawal of liquid or liquefied hydrocarbons into or out of an underground hydrocarbon storage facility.

(9) Leak detector--A device capable of detecting by chemical or physical means the presence of hydrocarbon vapor or the escape of vapor through a small opening.

(10) Liquid or liquefied hydrocarbons--Crude oil and products, derivatives, or by-products of oil or gas that are:

(A) liquid under standard conditions of temperature and pressure;

(B) liquefied under the temperatures and pressures at which they are stored; or

(C) stored under conditions that necessitate the use of displacement fluids to withdraw them from storage.

(11) Operator--The person recognized by the commission as being responsible for the physical operation of an underground hydrocarbon storage facility, or such person's authorized representative.

(12) Owner--The person recognized by the commission as owning all or part of a storage facility, or such person's authorized representative.

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

(14) Pollution--Alteration of the physical, chemical, or biological quality of, or the contamination of, water that makes it harmful, detrimental, or injurious to humans, animal life, vegetation, or property, or to public health, safety, or welfare, or impairs the usefulness or the public enjoyment of the water for any lawful or reasonable purpose.

(15) Process or transfer area--Any area at an underground hydrocarbon storage facility where hydrocarbons are physically altered by equipment, including dehydrators, compressors, and pumps, or where hydrocarbons are transferred to or from trucks, rail cars, or pipelines.

(16) Underground hydrocarbon storage facility or storage facility--A facility used for the storage of liquid or liquefied hydrocarbons in an underground salt formation, including surface and subsurface rights, appurtenances, and improvements necessary for the operation of the facility.

(b) Permit required.

(1) General. No person may create, operate, or maintain an underground hydrocarbon storage facility without obtaining a permit from the commission. A permit issued by the commission for such activities before the effective date of this section shall continue in effect until revoked, modified, or suspended by the commission, or until it expires by its terms. The provisions of this section apply to permits for underground hydrocarbon storage facility operations issued prior to the effective date of this section, except as specifically provided in this section.

(2) Conflict with other requirements. If a provision of this section conflicts with any provision or term of a commission order, field rule, or permit, the provision of such order, field rule, or permit shall control.

(c) Application

(1) Information required. An application for a permit to create, operate, or maintain an underground hydrocarbon storage facility shall be filed with the commission by the owner or operator, or proposed owner or operator, on the prescribed form. The application shall contain the information necessary to demonstrate compliance with the applicable state laws and commission regulations.

(2) Permit amendment. An application for amendment of an existing underground hydrocarbon storage facility permit shall be filed with the commission:

(A) prior to any planned enlargement of a cavern in excess of the permitted cavern capacity by solution mining;

(B) when required in accordance with paragraph (3) of this subsection;

(C) prior to the drilling of any additional hydrocarbon storage wells;

(D) prior to any increase in the volume of liquid or liquefied hydrocarbons stored in the cavern in excess of the permitted storage volume; or

(E) any time that conditions at the storage facility deviate materially from conditions specified in the permit or the permit application.

(3) Increase in capacity. The owner or operator of a storage facility shall notify the commission if information indicates that the capacity of a cavern exceeds the permitted cavern capacity by 20% or more. Such notification shall be made in writing to the commission within 10 days of the date that the owner or operator knows or has reason to know that the cavern capacity exceeds the permitted capacity by 20% or more. The notification shall include a description of the information that indicates that the permitted cavern capacity has been exceeded, and an estimate of the current cavern capacity. Upon receipt of such information, the commission or its designee may take any one or more of the following actions:

(A) require the permittee to comply with a compliance schedule that lists measures to be taken to ensure that conditions at the storage facility do not pose a danger to life or property, and that no waste of hydrocarbons, uncontrolled escape of hydrocarbons, or pollution of fresh water occurs;

(B) require the permittee to file an application to amend the underground hydrocarbon storage facility permit;

(C) modify, cancel, or suspend the permit as provided in subsection (f) of this section; or

(D) take enforcement action.

(4) Related activities. An application for a permit to dispose of saltwater or other oil and gas waste arising out of or incidental to the creation, operation, or maintenance of an underground hydrocarbon storage facility shall be filed in accordance with applicable commission requirements.

(d) Standards for underground storage zone.

(1) Impermeable salt formation. An underground hydrocarbon storage facility may be created, operated, or maintained only in an impermeable salt formation in a manner that will prevent waste of the stored hydrocarbons, uncontrolled escape of

hydrocarbons, pollution of fresh water, and danger to life or property. Natural gas storage operations are not authorized under the provisions of this section. A permit under §3.97 of this title (relating to Underground Storage of Gas in Salt Formations) is required to convert from storage of liquid or liquefied hydrocarbons to storage of natural gas in an underground salt formation.

(2) Fresh water strata. The applicant must submit with the application a letter from the Texas Natural Resource Conservation Commission stating the depth to which fresh water strata occur at each storage facility.

(e) Notice and hearing.

(1) Notice requirements. Such notice shall be given no later than the date the application is mailed to or filed with the commission. The applicant shall give notice of an application for a permit to create, operate, or maintain an underground hydrocarbon storage facility, or to amend an existing storage facility permit, by mailing or delivering a copy of the application form to:

(A) the surface owner of the tract where the storage facility is located or is proposed to be located;

(B) the surface owner of each tract adjoining the tract where the storage facility is located or is proposed to be located;

(C) each oil, gas, or salt leaseholder, other than the applicant, of the tract on which the storage facility is located or is proposed to be located;

(D) each oil, gas, or salt leaseholder of any tract adjoining the tract on which the storage facility is located or is proposed to be located;

(E) the county clerk of the county where the storage facility is located or is proposed to be located; and

(F) if the storage facility is located or proposed to be located within city limits, the city clerk or other appropriate city official.

(2) Publication of notice. Notice of the application, in a form approved by the commission or its designee, shall be published by the applicant once a week for three consecutive weeks in a newspaper of general circulation in the county or counties where the facility is or is proposed to be located. The applicant shall file proof of publication prior to any hearing on the application or administrative approval of the application.

(3) Notice by publication. The applicant shall make diligent efforts to ascertain the name and address of each person identified under paragraph (1)(A)-(D) of this subsection. The exercise of diligent efforts to ascertain the names and addresses of such persons

shall require an examination of the county records where the facility is located and an investigation of any other information of which the applicant has actual knowledge. If, after diligent efforts, the applicant has been unable to ascertain the name and address of one or more persons required to be notified under paragraph (1)(A)-(D) of this subsection, the notice requirements for those persons are satisfied by the publication of the notice of application as required in paragraph (2) of this subsection. The applicant must submit an affidavit to the commission specifying the efforts that were taken to identify each person whose name and/or address could not be ascertained.

(4) Hearing required for new permits. A permit application for a new underground hydrocarbon storage facility will be considered for approval only after notice and hearing. The commission will give notice of the hearing to all affected persons, local governments, and other persons who express, in writing, an interest in the application. After hearing, the examiner shall recommend a final action by the commission.

(5) Hearing on permit amendments.

(A) An application for an amendment to an existing storage facility permit may be approved administratively if the commission receives no protest from a person notified pursuant to the provisions of paragraph (1) of this subsection, or from any other affected person.

(B) If the commission receives a protest from a person notified pursuant to paragraph (1) of this subsection or from any other affected person within 15 days of the date of receipt of the application by the commission, or of the date of the third publication, whichever is later, or if the commission determines that a hearing is in the public interest, then the applicant will be notified that the application cannot be approved administratively. The commission will schedule a hearing on the application upon written request of the applicant. The commission will give notice of the hearing to all affected persons, local governments, and other persons who express, in writing, an interest in the application. After hearing, the examiner shall recommend a final action by the commission.

(C) If the application is administratively denied, a hearing will be scheduled upon written request of the applicant. After hearing, the examiner shall recommend a final action by the commission.

(f) Modification, cancellation, or suspension of a permit.

(1) General. Any permit may be modified, suspended, or canceled after notice and opportunity for hearing if:

(A) a material change in conditions has occurred in the operation, maintenance, or construction of the storage facility, or there are material deviations from the information originally furnished to the commission. A change in conditions at a facility that does not affect the safe operation of the facility or the ability of the facility to operate without causing waste of hydrocarbons or pollution is not considered to be material;

(B) fresh water is likely to be polluted as a result of continued operation of the facility;

(C) there are material violations of the terms and provisions of the permit or commission regulations;

(D) the applicant has misrepresented any material facts during the permit issuance process; or

(E) injected fluids are escaping or are likely to escape from the storage facility.

(2) Imminent dangers. Notwithstanding the provisions of paragraph (1) of this subsection, in the event of an emergency that presents an imminent danger to life or property, or where waste of hydrocarbons, uncontrolled escape of hydrocarbons, or pollution of fresh water is imminent, the commission or its designee may immediately suspend a storage facility permit until a final order is issued pursuant to a hearing, if any, conducted in accordance with the provisions of paragraph (1) of this subsection. All operations at the facility shall cease upon suspension of a permit under this paragraph.

(g) Transfer of permit. A storage facility permit may not be transferred without the prior approval of the commission or its designee. Until such transfer is approved by the commission or its designee, the proposed transferee may not conduct any activities otherwise authorized by the permit. The following procedure shall be followed when requesting approval for transfer of a permit.

(1) Request. Prior to transferring either ownership or operation of a storage facility, the permittee shall file a request for transfer of the permit with the commission. Such request may not be filed unless a completed Form P-4, signed by both the permittee and the proposed transferee, has been filed with the commission.

(2) Approval. The commission, or its designee, shall approve the transfer of a storage facility permit, provided:

(A) the proposed transferee is not the subject of any unsatisfied commission enforcement order at the time of the request for permit transfer; and

(B) there are no existing violations of any commission regulation, order, or permit at the storage facility at the time of the request for permit transfer that have been documented by the commission, or its employees, unless the proposed transferee agrees to correct the violations according to a compliance schedule approved by the commission, or its designee.

(3) Good cause. Notwithstanding paragraph (2) of this subsection, for good cause shown the commission or its designee may require public notice and opportunity for hearing prior to taking action on a request for transfer of a permit. Such request may be denied after notice and opportunity for hearing if the commission or its designee finds that transfer of the permit would not be in the public interest.

(h) Safety. The following safety requirements shall apply to all underground hydrocarbon storage facilities, except as specifically provided otherwise. Provided, however, the provisions of this subsection shall not apply to any hydrocarbon storage well that is out of service and disconnected from all surface piping. Notwithstanding the compliance time periods specified in paragraphs (1)-(15) of this subsection, a new storage facility permitted under this section must have all required safety measures and equipment in place before commencement of storage operations at the facility. All storage facilities that are permitted on the effective date of this section must have such safety measures and equipment in place within the period of time specified. Further, until such a facility has all the safety measures and devices required by paragraphs (2)-(7) and (13)-(15) of this subsection in place, the facility must have an attendant on site at all times.

(1) Monitoring of injection and withdrawal operations. All hydrocarbon injection and withdrawal activities shall be continuously monitored by an individual who is trained and experienced in such activities. Any facility that is unattended during injection and withdrawal activities shall have company personnel on call at all times. On-call personnel must be able to reach the facility within 30 minutes from the time a potential problem at the storage facility is noted by the individual monitoring the injection or withdrawal activities.

(2) Emergency shutdown valves.

(A) The requirements of this paragraph do not apply to underground hydrocarbon storage facilities storing only crude oil.

(B) Within two years of the effective date of this section, emergency shutdown valves shall be installed on the product and brine sides of each hydrocarbon storage well and, if required under paragraph (3) of this subsection, on fresh water piping to the well. An operator may request an exception to the compliance date of this subparagraph and propose an alternative workover schedule for approval by the commission or its designee. A storage well that is out of service and is disconnected from surface piping shall be exempt from this requirement until reactivated for hydrocarbon storage. Emergency shutdown valves shall meet the following requirements.

(i) Each emergency shutdown valve shall be capable of activation at each storage well, at the on-site control center if one exists, at the remote control center if one exists, and at a location that is reasonably anticipated to be accessible to emergency response personnel at any facility that does not have an on-site control center that is attended 24 hours per day.

(ii) Each emergency shutdown valve shall be an automatic fail-closed valve that automatically closes when there is a loss of pneumatic pressure, hydraulic pressure, or power to the valve.

(iii) Each emergency shutdown valve shall be closed and opened at least monthly.

(iv) Each emergency shutdown valve system shall be tested at least twice each calendar year at intervals not to exceed 7 1/2 months. The test shall consist of activating the actuation devices, checking the warning system, and observing the valve closure.

(C) If an emergency shutdown valve system fails to operate as required, the storage well shall be immediately shut in until repairs are completed, unless:

(i) a backup emergency shutdown valve is in operation on the same piping; or

(ii) an attendant is posted at the well site to provide immediate manual shut-in.

(3) Brine and fresh water piping.

(A) Brine piping from the wellhead to the emergency shutdown valve shall be designed for the maximum wellhead pressure on the hydrocarbon side of the well.

(B) Fresh water piping, if any, must either be:

(i) isolated from the wellhead when fresh water is not being injected into the well; or

(ii) designed for the maximum wellhead pressure on the hydrocarbon side of the well and equipped with an emergency shutdown valve.

(4) Overfill detection and automatic shut-in methods.

(A) The requirements of this paragraph shall not apply to an underground hydrocarbon storage facility storing only crude oil.

(B) The requirements of this paragraph shall not apply to a storage well that is out of service and disconnected from surface piping until the well is reconnected for hydrocarbon storage.

(C) Within one year of the effective date of this section, each storage cavern shall have at least one of the following devices or methods in operation. Within two years of the effective date of this section, each storage cavern shall have at least two of the following devices or methods in operation:

(i) a safety casing or annular tubing string filled with a non-volatile fluid and equipped with a pressure sensor switch set to automatically close all emergency shutdown valves in response to a preset pressure;

(ii) a preset pressure sensor switch on the brine piping that is set to automatically close all emergency shutdown valves in response to a preset pressure. This pressure sensor may be used in conjunction with weep hole(s) on a safety string that is concentric with the brine string, or in conjunction with weep hole(s) on the brine string;

(iii) a device on the brine string or brine piping that detects hydrocarbon in the brine by physical or chemical characteristics and that is set to automatically close all emergency shutdown valves in response to hydrocarbon detection;

(iv) an instrument that detects a rapid increase in the brine flow rate indicative of hydrocarbon in the brine and that is set to automatically close all emergency shutdown valves in response to a preset flow rate or differential flow rate; or

(v) an alternate device or method approved by the commission or its designee.

(5) Leak detectors.

(A) The provisions of subparagraphs (B)-(D) of this paragraph shall not apply to underground hydrocarbon storage facilities storing only crude oil.

(B) Within two years of the effective date of this section, a leak detector shall be installed and in operation at the wellhead of each hydrocarbon storage well and at each process and transfer area and each surface vessel area that contains liquid or liquefied hydrocarbons. These leak detectors shall be integrated with the warning system required in paragraph (13)(A) of this subsection.

(C) Within two years of the effective date of this section, leak detectors shall be installed and in operation at four locations that are evenly spaced around the perimeter of the brine pit(s).

(D) Leak detectors shall be tested twice each calendar year at intervals not to exceed 7 1/2 months and, when defective, repaired or replaced within 10 days.

(6) Brine system gas vapor control.

(A) The provisions of this paragraph shall not apply to underground hydrocarbon storage facilities storing only crude oil.

(B) Within two years of the effective date of this section, gas vapor control devices shall be installed and in operation at each brine pit system to ignite or capture hydrocarbon vapors that are heavier than air. Control devices shall consist of at least one of the following:

(i) a flare on the brine system upstream from the brine discharge point;

(ii) a hydrocarbon liquid knockout vessel and degasifier;

(iii) pilot lights on the berm of each brine pit; or

(iv) an alternative method designed to provide a reliable, localized point of ignition to prevent the formation of a vapor cloud.

(C) Brine system gas vapor control systems shall be inspected twice each calendar year at intervals not to exceed 7 1/2 months.

(7) Fire detection devices or methods.

(A) Within two years of the effective date of this section, fire detection devices or methods shall be installed and in operation at all process and transfer areas. Fire detection devices or methods specified in this paragraph shall be integrated with the warning system required in paragraph (13)(A) of this subsection. Fire detection shall consist of at least one of the following:

(i) fire detectors;

(ii) heat sensors, including meltdown and fused devices; or

(iii) camera surveillance at facilities that are attended at an on-site control room 24 hours per day.

(B) Fire detectors shall be tested twice each calendar year at intervals not to exceed 7 1/2 months and, when defective, repaired or replaced within 10 days.

(8) Emergency response plan. Within six months of the effective date of this section, each storage facility shall submit to the commission a written emergency response plan. The plan shall address spills and releases, fires, explosions, loss of electricity, and loss of telecommunication services. The plan shall describe the storage facility's emergency response communication system, procedures for coordination of emergency communication and response activities with local emergency planning committees and other local authorities, use of warning systems, procedures for citizen and employee emergency notification and evacuation, and employee training. The

initial plan must be designed based upon the existing safety measures at the facility. The plan shall be updated as changes in safety features at the facility occur, or as the commission or its designee requires. The plan shall include a plat of the facility that shows the location of wells, processing areas, loading racks, brine pits, and other significant features at the site. A copy of the plan shall be provided to the local emergency response planning committee and to any other local governmental entity that submits a written request for a copy of the plan to the operator. Copies of the plan shall also be available at the storage facility and at the company headquarters.

(9) Notification of emergency or uncontrolled release.

(A) Emergency response personnel. Each operator shall notify the county sheriff's office, the county emergency management coordinator, and any other appropriate public officials, which are identified in the emergency response plan, of any emergency that could endanger nearby residents or property. Such emergencies include, but are not limited to, an uncontrolled release of hydrocarbons from a storage well, or a leak or fire at any area of the storage facility. The operator shall give notice as soon as practicable following the discovery of the emergency. At the time of the notice, the operator shall report an assessment of the potential threat to the public.

(B) Commission. The operator shall report to the appropriate commission district office as soon as practicable any emergency, significant loss of fluids, significant mechanical failure, or other problem that increases the potential for an uncontrolled release. The operator shall confirm the report in writing within five working days.

(10) Public education. Within six months of the effective date of this section, each facility operator shall establish a continuing educational program to inform residents within a one-mile radius of a hydrocarbon storage facility of emergency notification and evacuation procedures.

(11) Annual emergency drill. Annually, each operator shall conduct a drill that tests response to a simulated emergency. Written notice of the drill shall be provided to the appropriate commission district office, the county emergency management coordinator, and the county sheriff's office at least seven days prior to the drill. Local emergency response authorities shall be invited to participate in all such drills. The operator shall file a written evaluation of the drill and plans for improvements with the appropriate district office and the county emergency management coordinator within 30 days after the date of the drill.

(12) Employee safety training.

(A) Within six months of the effective date of this section, each operator shall prepare and implement a plan to train and test each employee at each underground hydrocarbon storage facility on operational safety to the extent applicable to the employee's duties and responsibilities. The facility's emergency response plan shall be included in the training program.

(B) Each operator shall hold a safety meeting with each contractor prior to the commencement of any new contract work at an underground hydrocarbon storage facility. Emergency measures, including safety and evacuation measures specific to the contractor's work, shall be explained in the contractor safety meeting.

(13) Warning systems and alarms.

(A) Within two years of the effective date of this section, all leak detectors, fire detectors, heat sensors, pressure sensors, and emergency shutdown instrumentation shall be integrated with warning systems that are audible and visible in the local control room and at any remote control center. The circuitry shall be designed so that failure of a detector or heat sensor, excluding meltdown and fused devices, to function will activate the warning.

(B) A manually operated alarm shall be installed at each attended storage facility within two years of the effective date of this section. The alarm shall be audible in areas of the facility where personnel are normally located.

(14) Wind socks. Within one year of the effective date of this section, at least one wind sock that is visible at any time from any normal work location within the storage facility shall be installed at the facility.

(15) Barriers. Within one year of the effective date of this section, barriers designed to prevent unintended impact by vehicles and equipment shall be placed around above-grade hydrocarbon piping, hydrocarbon process equipment, and surface hydrocarbon storage vessels in areas where vehicles may normally be expected to travel.

(i) Cavern capacity and configuration.

(1) Crude oil storage. The provisions of this subsection shall not apply to underground hydrocarbon storage facilities where only crude oil is stored.

(2) Before storage operations begin. The capacity and configuration of each hydrocarbon storage cavern (both salt domes and bedded salt) shall be determined by sonar survey before storage operations begin in a newly completed cavern.

(3) Salt domes. The capacity and configuration of each salt dome hydrocarbon storage cavern shall be determined by sonar survey at least once every 10 years.

(4) Bedded salt. The configuration of the roof of each hydrocarbon storage cavern in bedded salt shall be determined by downhole log or an alternate method approved by the commission or its designee at least once every five years.

(5) Filing results. Sonar and roof monitoring survey results shall be filed with the commission within 30 days after the survey.

(6) Out-of-service caverns. A sonar or roof monitoring survey is not required for a cavern that is out of service. A sonar or roof monitoring survey shall be performed before any cavern that has been out of service is returned to service.

(j) Well completion, casing, and cementing. Hydrocarbon storage wells shall be cased and the casing strings cemented to prevent fluids from escaping to the surface or into fresh water strata, or otherwise escaping and causing waste or endangering public safety or the environment.

(1) New wells.

(A) All hydrocarbon storage wells drilled in salt domes after the effective date of this section shall have at least two casing strings cemented into the salt formation. Sufficient cement shall be used to fill the annular space outside the casing from the casing shoe to the ground surface, or from the casing shoe to a point at least 200 feet above the shoe of the previous casing string.

(B) All hydrocarbon storage wells in bedded salt drilled after the effective date of this section shall have all casing strings cemented with sufficient cement to fill the annular space outside each casing string from the casing shoe to the ground surface.

(2) Well completion report. A well completion report shall be filed in accordance with the instructions on the form prescribed by the commission within 30 days after a storage well is completed and before solution mining to create the cavern begins.

(k) Operating requirements.

(1) Operating pressure. The operating pressure of each hydrocarbon storage well shall not exceed the permitted maximum operating pressure for that well. The permitted maximum operating pressure is that pressure specified in the commission permit or order, or, if not specified in the permit or order, that pressure stated in the application or the application for amendment to a permit or order. The maximum operating pressure at the shoe of the lowermost cemented casing shall not exceed 0.8 pounds per square inch per foot of depth.

(2) Volume of hydrocarbons stored. The quantity of hydrocarbons stored in a cavern shall not exceed the permitted maximum storage volume for that cavern. The permitted maximum hydrocarbon storage volume is that volume specified in the commission permit or order, or, if not specified in the permit or order, that volume stated in the application or the application for amendment to a permit or order.

(l) Monitoring requirements.

(1) Pressures. Each hydrocarbon storage well shall be equipped with pressure sensors that continuously monitor and display wellhead pressures on both the product and brine sides of the wellhead at the control room. Each hydrocarbon storage well with a safety string shall be equipped with a pressure sensor and the sensor shall continuously monitor the pressure on the safety string at the wellhead.

(2) Pressure gauges. Each hydrocarbon storage well shall be equipped with gauges on both the brine and hydrocarbon sides of the wellhead.

(3) Volumes injected and withdrawn. The volume of hydrocarbons injected into and withdrawn from each hydrocarbon storage well shall be measured by:

(A) flow meter; or

(B) an alternate method approved by the commission or its designee.

(4) Measurement performance. The accuracy of hydrocarbon volume measurement devices or methods required under paragraph (3) of this subsection shall be verified at least once each year by a person who is not an officer or employee of the owner or operator, or any affiliate of the owner or operator. For purposes of this section, an affiliate is any person or entity that owns, is owned by, or is under common ownership with the owner or the operator. In the case of meters, verification includes witnessing meter calibration or proving conducted by the owner or operator or an affiliate of the owner or operator.

(m) Reporting. The operator shall report maximum wellhead pressures on the hydrocarbon and brine sides of each hydrocarbon storage well and the net volumes of hydrocarbons injected into and withdrawn from each hydrocarbon storage well in accordance with the instructions on the annual report form prescribed by the commission.

(n) Records retention.

(1) Hydrocarbon injection and withdrawal data. The operator shall retain for five years records of hydrocarbon storage well pressures, interface levels (if any), hydrocarbons injected into and withdrawn from each well, and the hydrocarbon inventory of each cavern.

(2) Equipment data. The operator shall retain for five years documents and records pertaining to the installation, inspection, maintenance, and testing of equipment required under subsections (h) and (l) of this section. Records of any test of a safety device required under subsection (h) of this section shall be available for on-site inspection within 10 days of the date of the test.

(3) Extension during investigation. Any documents or records that contain information pertinent to the resolution of any pending regulatory enforcement proceeding shall be retained beyond the five-year period until the resolution of such proceeding.

(o) Testing.

(1) Integrity tests. Each hydrocarbon storage well shall be tested for integrity prior to being placed into service, at least once every five years, and after each workover that involves physical changes to any cemented casing string. The following requirements apply to all such integrity tests.

(A) A hydrocarbon storage well shall be tested for integrity by the nitrogen-brine interface method or an alternative approved by the commission, or its designee.

(B) A test procedure shall be filed with the commission for approval at least 10 days before the test date.

(C) The operator shall notify the district office at least five days prior to conducting any integrity test.

(D) A complete record of each integrity test shall be filed in duplicate with the district office within 30 days after testing is completed. The record shall include a chronology of the test, copies of all downhole logs, storage well completion information, pressure readings, volume measurements, temperature logs and readings, and an explanation of the test results that addresses the precision of the test in terms of a calculated leak rate.

(E) Storage well pressures shall be allowed to stabilize to a rate of change of less than 10 psi in 24 hours before the testing period begins.

(2) Alternative monitoring. An operator may request the commission or its designee to approve storage well pressure monitoring as an alternative to integrity testing for hydrocarbon storage wells that are out of storage service. An out-of-service storage well must be tested for integrity according to the procedures specified in paragraph (1) of this subsection before it may be returned to storage service.

(p) Plugging.

(1) Plug on abandonment. A hydrocarbon storage well shall be plugged upon permanent abandonment in a manner approved by the commission or its designee. A proposal for plugging shall be submitted to the commission in Austin for approval or modification prior to plugging. Following approval of a plugging plan, the operator shall file a notification of intent to plug at least five days prior to commencement of plugging operations. A plugging report shall be filed with the commission in Austin within 30 days after plugging.

(2) Alternative monitoring. As an alternative to plugging a hydrocarbon storage well that has been permanently deactivated, an operator may request approval by the commission or its designee of a plan to convert the storage well to a monitor well. A pressure monitoring plan must be submitted to the commission along with the request to convert the storage well to a monitoring well.

(q) Penalties.

(1) Penalties. Violations of this section may subject the operator to penalties and remedies specified in the Texas Natural Resources Code, Titles 3 and 11, and other statutes administered by the commission.

(2) Certificate of compliance. The certificate of compliance for any underground hydrocarbon storage facility may be revoked in the manner provided in §3.68 of this title (relating to Pipeline Connection; Cancellation of Certificate of Compliance; Severance).

(r) Applicability of other commission rules and orders. The owner or operator of an underground hydrocarbon storage facility is not relieved by this section of compliance with any other requirement of the Oil and Gas Division, or any requirement of the Liquefied Petroleum Gas Division or the Transportation/Gas Utilities Division.

UTAH

Utah Administrative Code

Title R649 (Oil, Gas and Mining; Oil and Gas), Rule R649-3 (Drilling and Operating Practices)

R649-3-25. Underground Disposal Of Drilling Fluids.

1. Operators shall be permitted to inject and dispose of reserve pit drilling fluids downhole in a well upon submitting an application for such operations to the division and obtaining its approval. Injection of reserve pit fluids shall be considered by the division on a case-by-case basis.

2. Each proposed injection procedure will be reviewed by the division for conformance to the requirements and standards for permitting disposal wells under R649-5-2 to assure protection of fresh-water resources.

3. The subsurface disposal interval shall be verified by temperature log, or suitable alternative, during the disposal operation.

4. The division shall designate other conditions for disposal, as necessary, in order to ensure safe, efficient fluid disposal.

VIRGINIA

EPA Region IV (DI) administers the Class II UIC program.

No statutes, regulations, or policies addressing slurry fracture injection, sub-fracture injection, or annular injection of drill cuttings. Determination would be made on a case-by-case basis.

WEST VIRGINIA

No regulations are in place that govern the injection of any fluids or materials, except for produced water, which is covered under the Class II program. A one-time request for slurry injection or other related technologies would be resolved administratively under the UIC program.

WYOMIING

General Agency, Board or Commission Rule
Oil and Gas Conservation Commission

Chapter 4. Environmental Rules (Underground Injection Control Program -- Enhanced Recovery)

Section 1. Pollution and Surface Damage (Forms 14A and 14B).

(a) These rules are intended to protect human health and the environment by avoiding contamination of the soils and underground and surface waters at drilling or producing locations. Applications to construct pits, provided for in these rules, shall be approved if the pit will not cause the contamination of surface or underground water, and endanger human health or wildlife. Approval by the Commission of applications for permits for reserve or produced water pits does not relieve the owner or operator of the obligation to comply with the applicable federal, local, or other state permits or regulatory requirements.

(b) The Commission exercises its regulatory authority over the construction, location, operation, and reclamation of oilfield pits within a lease, unit or communitized area which are used solely for the storage, treatment, and disposal of drilling, production and treater unit wastes. The following pits are subject to this regulation:

(i) reserve pits on the drilling location;

(ii) reserve pits off the location within a lease, unit or communitized area permitted by owner or unit operator drilling the well;

(iii) produced water retention pits, skim pits, and emergency production pits including the following

(A) pits associated with approved disposal wells which act as fluid storage, filtering or settling ponds prior to underground disposal in a Class II well;

(B) pits constructed for disposal of produced fluids in connection with oil and gas exploration and production used as part of the filtering and/or settling process upstream of an NPDES discharge point;

(C) pits constructed in association with heater treaters or other dehydration equipment used in production, such as free water knockouts, or first, second and third stage separators;

(D) pits constructed for blowdown or gas flaring purposes.

(iv) pits constructed for the storage and treatment of heavy sludges, oils, or basic sediment and water (BS&W) in connection with production operations;

(v) temporary pits constructed during well workovers, including spent acid and frac fluid pits;

(vi) permanent or temporary emergency use pits;

(vii) miscellaneous pits associated with oil and gas production not listed above.

(c) Permits. In addition to the permits required by the Commission and the Bureau of Land Management, the following agencies may also have authorities over the management of oil field wastes:

(i) The Wyoming Department of Environmental Quality administers the following regulatory programs:

(A) commercial ponds and pits used for the retention and disposal of fluids;

(B) Class I hazardous waste and nonhazardous waste wells under the Underground Injection Control Program;

(C) National Pollutant Discharge Elimination System Program;

(D) regulations for releases of oil and hazardous substances into waters of the state and Wyoming Contingency Plan;

(E) roadspreading, landspreading, and landfarming of exploration and production wastes;

(F) solid waste disposal facilities operated by municipalities and privately by the oil and gas industry;

(G) cathodic protection wells;

(H) underground storage tanks;

(I) sanitary waste treatment systems; and

(J) air quality standards.

(ii) The Bureau of Land Management administers surface operating standards for oil and gas exploration and development on federal lands, Indian lands and/or leases in Wyoming;

(iii) The Office of the State Engineer regulates surface water appropriation and the use of water supply wells, the beneficial use of produced water, and coalbed methane development wells;

(iv) The United States Fish and Wildlife Service administers the Migratory Bird Treaty Act in Wyoming. Oil and gas owners or operators have to be aware of the obligation to comply with this regulation as they permit, construct, and maintain all facilities that may contain hydrocarbons or produced waters. Appendix A includes information on that legislation.

(d) Oil and Gas Commission Pit Permits. No retaining pit or below grade structure used for the containment of fluids, as defined in this section, shall be constructed unless Form 14A (Produced Water Pits) or 14B (Temporary or Reserve Pits), (Application For Permit To Use Earthen Pit), has been submitted to and approved by the Supervisor. Sumps used for the temporary collection of associated wastes are exempt from this permit requirement.

(e) Owners or operators of produced water retaining pits in operation prior to June 1, 1984, may continue to use such pits as long as the operation conforms to the current requirements of new pits. Owners of existing pits shall be responsible for providing the information included on Form 14A upon request of the Supervisor.

(f) The Supervisor may administratively approve field-wide or area-wide applications covering the standardized construction and operation of earthen retaining pits.

(g) Optional Form 18 (Soil & Groundwater Information), is provided for the operator's use, if they choose, to supplement Forms 14A and 14B to record and document shallow groundwater and subsoil types when they drill shallow holes such as the rat hole, mouse hole or conductor on the drill site. This Form can be used to demonstrate that a well is not in a critical area where groundwater is at a depth of less than twenty feet (20') or in an area that has permeable subsoil.

(h) Centralized Pits. Owners or operators must obtain approval of the Supervisor for the location, construction and closure of noncommercial centralized pits located within a lease, unit, or communitized area used for field operations. Requirements may be more stringent than individual reserve or produced water pits depending on pit size, waste type, and location. Applicants upon request of the Supervisor, shall provide additional notice, plats and plan views, and information relative to the location of water supplies, residences, schools, hospitals, or other structures where people are known to congregate, site security, groundwater monitoring and leak detection. These permits will be issued for a term of five (5) years and may be renewed at the discretion of the Supervisor.

(i) Emergency Pits. Prior to construction, permanent emergency pits must be approved on Form 14B (Application For Permit To Use And Construct Earthen Pit For Temporary Use Or For Reserve Pit). Within twenty-four (24) hours of the first business day after construction of a temporary emergency pit or use of a permanent emergency pit, the owners or operators shall verbally advise the Supervisor of the existence of the pit and of the estimated time it will be in use.

(j) Reserve Pits. Form 14B must be submitted and approved in conjunction with an Application for Permit to Drill (Form 1). Approval of this permit must be obtained before drilling commences. The staff must be provided at least one (1) working day to evaluate the location (for distance from surface waters, depth to useable ground water, soils, distance from human habitation, etc.) and to evaluate the fluids which potentially will be retained in the pit (for types of drilling and completion fluids proposed for use, for presence of salt sections, and for the length of time the pit will be in use, etc.). The Commission may request additional information to complete its evaluation. Owners and operators using closed systems who wish to use a pit to receive drill cuttings must apply for and receive permission to construct on Form 14B.

(k) Permits are valid for a term of one (1) year from the date of issuance unless an extension has been approved for the Application for Permit to Drill (Form 1) and for as long as the permit conditions are met. Falsification of information on the application or filing of an incomplete application will result in automatic denial of the request.

(l) Workover and Completion Pits. Workover pits and pits used for initial completion and recompletion of wells are subject to the following approval and operating requirements.

(m) Pits in critical areas: Approval of workover and completion pits, meeting any of the following criteria, must be applied for and obtained on Form 14B prior to their construction and use:

(i) pits which are located within one-quarter (1/4) mile of water supplies, residences, schools, hospitals, or other structures where people are known to congregate;

(ii) pits in areas when groundwater at the pit location is less than twenty feet (20') from the surface;

(iii) pits which are located within five hundred feet (500') of wetlands, ponds, lakes, perennial drainages or within a floodplain;

(iv) pits in areas where produced waters from wells are greater than 10,000 milligrams per liter total dissolved solids; or

(v) pits located in pervious subsoils such as sands, scoria, river bottom gravel, loams, etc. are present at the pit location.

(n) Application may be done in the following manner:

(i) submitting Form 14B application for individual new (concurrent with filing an Application for Permit to Drill) (Form 1) or existing wells;

(ii) submitting Form 14B application for a field or unit wide permit, listing all wells meeting any of the above criteria.

(o) If the owner or operator complies with the approved Form 14B terms and conditions, no further approval to construct and use workover or completion pits will be required for those well sites. However, subsequent reporting, within thirty (30) days of completion of operations on Form 4 (Sundry Notice), is required each time a pit is constructed and used. Alternative reporting requirements such as annual reporting may be approved by the Supervisor.

(p) Pits in non-critical areas: Workover and completion pits not meeting any of the criteria listed in subsection m(i) through (v) will require either:

(i) submittal of a Form 14B application for a field or individual well basis to receive a one-time approval to construct and use workover and completion pits. As long as the owner or operator complies with the approved Form 14B terms and conditions, no further application/notice will be required for future construction and use of workover and completion pits.

(ii) notification to the Supervisor via Sundry Notice (Form 4), subsequent to the construction and use of a workover or completion pit. This must be submitted within thirty (30) days of completion of operations and include the following information:

(A) schematic diagram showing the location of the workover or completion pit in relation to existing production equipment;

(B) length of time the pit was in use; and

(C) statement addressing the types of fluids placed in the pit and that those fluids were removed prior to closure.

(q) General. Upon review of Form 14B applications, the Commission staff will evaluate well locations (for distances from surface waters, depth to useable groundwater, soils, distances from human habitation, etc.). Special precautions or operational restrictions may be required by the Supervisor at these well facilities in order to avoid contamination of groundwater and surface at the well location.

(r) Workover pits should retain only RCRA exempt wastes. Other wastes should be managed in tanks for later recycling, reuse, or proper disposal. Owners or operators should design workover or completion procedures so that additives will be expended while correcting the down-hole problems. Workover and completion pits shall be open only for the duration of operations and must be closed within thirty (30) days after the operation is complete.

(s) Produced Water Pits. Form 14A must be submitted and approved prior to use of a produced water pit. The information required includes a standard water analysis, (Form 17) to include oil and grease, maximum and average estimated inflow, size of pit, freeboard capacity, origin of pit contents, method of disposal of pit contents, maximum fluid level above average ground level, distance to closest surface water, depth to groundwater, subsoil type, and type of sealing material. A plan view map and topographic map of sufficient size and detail to determine surface drainage system and all natural waterways and irrigation systems, if applicable, must be attached. The Commission may request additional information.

(t) Below Grade Structures (Tinhorns). For the purpose of its regulation, the Commission requires below grade structures (including tinhorns) used to receive oil, condensate, or produced water, to be applied for on Form 14A. Construction must be done in accordance with good engineering practice and the staff must be provided the opportunity to inspect prior to any use. A written monitoring program for all permitted below grade structures must be submitted and approved by the staff.

(u) Marking. The owner shall mark each pit in a conspicuous place with his name and the legal description of the location of the pit and shall take all necessary means and precautions to preserve these markings. Exempted from this requirement are pits in close proximity to injection or producing wells marked in accordance with Chapter 3, Section 19.

(v) Location. When any retaining pit is located in an area with a high potential for communication between the pit contents and surface water or shallow ground water, or to provide additional protection to human beings when operations are conducted in close proximity to water supplies, residences, schools, hospitals, or other places where people are known to congregate, or to provide protection to livestock and wildlife, the Commission may require such modifications or changes in the owner's plans as it deems necessary including, but not limited to, running a closed system, lining the pit, installing monitoring systems and providing additional reporting, or any other reasonable requirement that will facilitate the protection of fresh water. In areas where ground water is less than twenty feet (20') below the surface, a closed system must be utilized.

(w) Unlined pits shall not be constructed in fill. Pits of any kind shall not be constructed in drainages, or in the floodplain of a flowing or intermittent stream, or in an area where there is standing water during any portion of the year. Ground and surface water maps are available for review or consultation at the Commission, the USGS, or the State Engineer's Office.

(x) Construction. Lining of the pit with reinforced oilfield grade material, compatible with the waste to be received, will be required by the Supervisor or Commission under certain circumstances including, but not limited to, sandy soils, shallow groundwater, groundwater recharge areas, drilling or production locations immediately adjacent to the Green River or the Colorado River drainage and other sensitive environments or circumstances identified by the Commission. Pits constructed in fill or those used to retain oil base drilling muds, high density brines, and/or completion or treating fluids must be lined. Pits constructed to retain produced water with a total dissolved solids concentration in excess of 10,000 milligrams per liter must be lined. The Supervisor, on a case by case basis, will determine if pits retaining water with a total dissolved solids concentration less than 10,000 milligrams per liter will be required to be lined. The Commission staff must be provided at least twenty-four (24) hours notice of commencement of construction and/or of closure of pits so that an inspection can be made. Additionally, the following construction standards for pits are required to be met or exceeded:

(i) Soil mixture liners, recompacted clay liners, and manufactured liners must be compatible with the waste contained. On request of the Supervisor, the operator must provide evidence of the chemical resistance of the liner selected for use.

(ii) Liners constructed of synthetic materials must meet the following specifications: a 9 to 12 mil thickness, greater than 20% elongation at failure, puncture strength of 60 pounds, tear strength of 50 pounds, and permeability less than 10-7 cm/sec. Joints must be overlapped a minimum of 2 inches and seams sealed as recommended by the manufacturer. Blemishes, holes, or scars must be repaired per manufacturer's recommendation. Breaches in the liner for siphons or other equipment must be reinforced.

(iii) Slopes for soil mixture liners or recompacted liners shall not exceed 3:1. Slopes for manufactured liners shall not exceed 1:1.

(iv) Reasonable provisions for protection of liners during filling and emptying activities must be included in the construction plans.

(v) Manufactured liners must be installed over smooth fill subgrade which is free of pockets, loose rocks, or other materials which could damage the liner. Sand, sifted dirt, or bentonite are suggested. At no time will straw or any other organic material except synthetic cushion fabric designed for that purpose be used for a liner cushion. Installation of synthetic or soil mixture liners must be in accordance with accepted engineering practice.

(vi) Liner edges must be secured. The Commission prefers that liner edges be placed in a trench which is deep enough to receive approximately one foot (1') of compacted soil which will anchor the material.

(vii) Monitoring systems may be required for pits constructed in sensitive areas. Such pits must be operated in a manner that avoids damage to liner integrity. Periodic inspections, weekly at a minimum, of pits must be made by the owner or operator and documentation of such inspections may be required to be submitted to the Supervisor at his request.

(viii) Liquids must be kept at a level that takes into account extreme precipitation events and prevents overtopping and unpermitted discharges. Appendix B includes average annual precipitation rates for the state.

(y) Operation. Owners or operators will take such reasonable measures to manage pits so that they are used solely for retention or disposal of fluids associated with the operation for which the pit was originally constructed and for which the permit was granted. Reserve pits cannot be used as production pits; separate pits must be constructed and permitted. Permits are granted taking into consideration the salinity, hydrocarbon content, pH, and other characteristics of the fluids which may be detrimental to the environment if they were to be directly applied to soils. Use of a pit by persons other than the owner or operator is prohibited unless approved by the Supervisor and by the owner or operator of the pit. Pits shall not receive, collect, store, or dispose of any wastes that are listed or defined as hazardous wastes and regulated under Subtitle C of RCRA, except in accordance with state and federal hazardous waste laws and regulations. The pit permit or approval is automatically canceled if these provisions are not met. See Appendix C for additional information.

(z) Unused commercial products shall not be disposed with exempt oilfield wastes. The commingling of any listed hazardous waste with the otherwise exempt pit contents may render the entire mixture a hazardous waste and results in closing the pit under the RCRA hazardous waste regulations. All reasonable efforts should be made to completely use commercial products. Products should be returned to the vendor if appropriate, or segregated from other wastes for management or disposal. Oil base muds must be segregated from water base drilling fluids because pit closure is complicated by their presence. Mixing and treating of oil based and water-based muds can be allowed with approval of the Supervisor. Rigwash may be routed to the reserve pit provided care is taken to avoid contamination of the pit contents by rig oil and other nonexempt wastes. See Appendix C for more information.

(aa) Where feasible, operators are encouraged to increase the use of solids removal equipment to minimize drilling fluid waste. The Commission encourages the recycling of drilling fluids and by administrative action approves the transfer of fluids. When removed as a product for use in a drilling operation on another lease, drilling fluid is not classified as a waste. If federal leases are involved, the owner or operator must obtain the approval of the BLM. The Supervisor requires the following information be included on the Form 14B or on a Sundry Notice (Form 4) estimated volume, estimated date of transfer, mud recap, analyses which include at a minimum, pH, chlorides, and oil and grease. To protect shallow groundwater, drilling muds with chlorides testing in excess of 3,000 parts per million or those containing hydrocarbons cannot be used in drilling operations until after the surface casing has been set.

(bb) Trash and sanitary waste should be properly contained and hauled to approved disposal locations, not retained in or disposed of in pits on location or downhole. Operators should consult the county sanitarian and/or the Department of Environmental Quality regarding appropriate disposal of sanitary wastes.

(cc) Reserve pits shall be completely fenced and, if oil or other harmful substances are present, netted or otherwise secured at the time the rig substructure has been moved from the location in a manner that avoids the loss of wildlife, domestic animals, or migratory birds. Because of the same concerns, produced water pits must be fenced and, if oil or other harmful substances are present, netted or secured in such a manner as to provide protection to wildlife, domestic animals, or migratory birds. The Commission recommends netting as the preferred means of securing pits. See Appendix A for information relative to the Migratory Bird Treaty Act. Owners or operators shall provide for devices on hydrogen sulfide flare stacks to discourage birds from perching. The Supervisor may make additional requests for security when operations are conducted in close proximity to residences, schools, hospitals, or other structures or locations where people are known to congregate.

(dd) Blowdown, flare, and emergency pits cannot be used for long-term storage or disposal.

(ee) All retaining pits shall be kept reasonably free of surface accumulations of oil and other liquid hydrocarbon substances and shall be cleaned within ten (10) days after discovery of the accumulation by the owner or notice from the Supervisor.

(ff) The owner or operator shall not pollute streams, underground water, or unreasonably damage or occupy the surface of the leased premises or other lands. At no time will the fluid contents of any pit be discharged or allowed to escape to the surface without prior approval through issuance of an NPDES permit by DEQ and other required authorization. At no time will drilling fluids be discharged into live waters or into any drainages that lead to live waters of the state. If liquid products of wells cannot be treated or destroyed, or if the volume of such products is too great for disposal by the usual method of onsite natural evaporation and burial of solids, the Supervisor must be consulted and the liquids disposed of by an approved method.

(gg) Testing. For the purpose of its regulation of oilfield pits and wastes, the Commission recognizes, and requires when it deems appropriate, the following tests:

(i) Standard Water Analysis - Form 17

(ii) Toxicity Characteristic Leaching Procedures

(iii) Oil and Grease or Total Petroleum Hydrocarbon (hh) Soil borings and soil testing must be performed by an independent engineering or geotechnical soil testing company or laboratory according to sound engineering practice in accordance with established industry standards. The logs of all borings, together with associated laboratory testing to classify soils and to measure soil strength, permeability, and other related parameters shall be submitted to the Supervisor.

(ii) Sampling procedures are subject to review by the Supervisor because variations in sampling protocol allow differentiation of waste fluid compositions due to normal distribution.

(jj) Closure. If the pit is proposed to be closed through the usual method of onsite natural evaporation and subsequent burial of solids, if pit treatment procedures are going to be applied, or if closure plans have changed from the original proposal approved on Form 14A or 14B, or any time wastes are disposed off-site, a Sundry Notice (Form 4) must be submitted and approved prior to closure. A list of approved commercial disposal facilities is available from the DEQ Water Quality Division. The Commission staff must be provided the opportunity to witness closure operations. Verbal notice at least twenty-four (24) hours prior to closure is required. Closure must be conducted in accordance with lease and landowner obligations and with local, state, and federal regulations:

(i) Oil, water, and other fluids must be immediately removed from emergency pits and disposed in accordance with the Commission's rules. In the case of temporary emergency pits, evaporation or percolation of fluids prior to closure is not an acceptable disposal method. Permitted permanent emergency pits will not require immediate closure after use and fluid removal;

(ii) Trenching or squeezing pits is expressly prohibited. Burial methods cannot compromise the integrity of manufactured, soil mixture, or recompacted clay liners without written approval by the Supervisor. One-time landspreading of reserve pit fluids on the drilling pad may be approved upon submittal of analyses, mud recaps and treating summaries, groundwater identification, and other information that is deemed appropriate. Prior approval must be obtained from the Supervisor if drilling fluid is disposed on the drill pad. A Sundry Notice (Form 4) with appropriate supporting detail must be submitted following the operation. Any offsite waste disposal is subject to DEQ regulations;

(iii) Closure standards and testing requirements for all pits will be determined by the Supervisor based upon site-specific conditions;

(iv) Pit solids showing high concentrations of salt (exchangeable sodium percentage above 15 by weight) must be removed from the location and disposed in a permitted facility, encapsulated, or chemically or mechanically treated;

(v) Oil based mud solids must be removed and disposed in a permitted facility, or mixed with soil to less than one percent oil (1%) and grease content by weight at burial, or road or landspread or landfarmed in accordance with DEQ rules. Burial after encapsulation or solidification will be approved if the stabilized mixture contains less than one percent (1%) leachable oil and grease.

(kk) Reserve pits shall be completely fenced and, those which contain oil or other harmful substances, netted or otherwise secured in a manner that prevents the loss of wildlife, domestic animals, or migratory birds at the time the rig substructure has been moved from the location.

(ll) All trash, paper, and unused structures or equipment must be removed from the location upon completion of operations. With landowner consent, operators may temporarily store equipment (such as drilling rigs) on a location while it awaits transfer. Reserve and produced water pits cannot be used for disposal of refuse, failed equipment parts, or unused chemicals. Proper closure of the pit is compromised by the inappropriate use of the pit for trash disposal and may result in revocation of the permit. Further, operators are encouraged to choose chemical additives which are lower in toxicity or do not exhibit RCRA hazardous characteristics. See Appendix D for suggestions. Additionally, operators are encouraged to refer to Material Safety Data Sheets provided by vendors as products are selected.

(mm) The Commission specifically prohibits the use of dispersants, wetting agents, surface reduction agents, surfactants, or other chemicals that destroy, remove, or reduce the fluid seal of a reserve pit and allow the fluids contained therein to seep, drain, or percolate into the soil underlying the pit.

(nn) Landfarming or landspreading must be approved by the DEQ. Jurisdiction over roadspreading or road application is shared by DEQ and the Commission. Roadspreading or road application is a process whereby wastes are incorporated into a roadbed, typically for beneficial use, with minimal environmental risk. The Commission is the agency responsible for permitting road applications of RCRA-exempt exploration and production wastes which include drilling fluids, produced water and produced water-contaminated soils, waste crude oil, sludges, and oil-contaminated soils inside the boundaries of a lease, unit, or communitized area. The roadspreading application shall include acceptable evidence of landowner consent and the information included on the Commission's Form 20. Landfarming, landspreading, and roadspreading shall be protective of human health and the environment and shall be performed in compliance with allother applicable State and Federal regulations and requirements.

(oo) The Commission may require testing of wastes and additional disposal requirements prior to closure of a pit if they have reason to believe exempt exploration and production wastes have been commingled with hazardous wastes, upon analysis of an operator's mud program, or in previously identified sensitive environments.

(pp) Commercial Treatment For Pit Closure. Any person, corporation, or company desiring to chemically and/or mechanically treat pits in Wyoming must apply for and receive permission to do so from the Commission after a public hearing. Types of approved treatments include enhanced evaporation, solidification, centrifuging, etc. The Commission will approve those methods that can successfully demonstrate a capability to accomplish some or all of the following criteria:

(i) compressive strengths that are appropriate for post drilling or production activities;

(ii) reductions in weight or volume of waste;

(iii) removal or reduction of harmful properties of waste; and

(iv) reduction or elimination of mobility or leachability of constituents.

(qq) An operator or owner wishing to treat pits for closure must submit, to the Commission on a Sundry Notice (Form 4), a plan outlining the objectives (e.g. waste volume reduction, toxicity reduction/removal, chemical fixation, etc.) that the treatment is designed to achieve. The Commission's approval, will be based upon the selected method's demonstrated capability to achieve the objectives described in the sundry notice. Consideration must be given to applicable federal, local, or state permits or regulatory requirements when performing mechanical or chemical treatment of pit wastes. A list of approved methods and vendors is available from the Commission.

(rr) Reclamation. Reclamation of unused production pits or any other temporary retaining pits, including reserve pits, shall be completed in as timely a manner as climatic conditions allow. Production pit areas and reserve pits will be reclaimed no later than one (1) year after the date of last use unless the Supervisor grants an administrative variance for just cause.

(ss) Site rehabilitation should be in accordance with reasonable landowner's wishes, and/or resemble the original vegetation and contour of the adjoining lands. Where practical, topsoil must be stockpiled during construction for use in rehabilitation. All disturbed areas on state lands will be reseeded. Appendix F includes information on seeding. The owner or operator shall advise the Supervisor of the completion of reclamation of a production or reserve pit by submitting a Sundry Notice (Form 4).

(tt) One-time Downhole Disposal. By formal order or by administrative action the Commission may approve of one-time disposal of a limited volume of fluid produced in the course of drilling operations from one specific well. This is not an operation designed for downhole disposal of drilling fluids from offsetting or additional wells.

This application is not to be confused with the approval of a Class II well for underground disposal of water produced in association with the recovery of hydrocarbons under the Underground Injection Control Program. Disposal by injection shall not be initiated until such time as approval has been granted by the Commission.

(uu) An application for approval of reserve pit fluid injection shall demonstrate that water in the proposed disposal interval is in excess of 10,000 milligrams per liter total dissolved solids or has received an aquifer exemption under Chapter 4, Section 12 and that fresh water or Underground Sources of Drinking Waters (USDW) will not be influenced by the disposal operation. Data to support this finding shall include, but not be limited to, the following:

(i) full detail of the casing, cementing, and completion of the well including cement logs;

(ii) formation tops and depths to the deepest USDW;

(iii) copies of the mud recaps, appropriate analyses of the fluid, and an estimate of the volume of the fluids to be disposed;

(iv) abandonment procedure and demonstration that the disposal zone can be isolated;

(v) maximum disposal pressure anticipated and information relative to fracture pressures of the confining zone. Pump pressure must be limited so that fractures will not extend to the base of a USDW and/or a groundwater aquifer;

(vi) the statement that the owner or operator will make arrangements to provide at least twenty-four (24) hours notice of disposal operation so that a Commission technician might be present as a witness; and

(vi) statement that on completion of the work a temperature survey or suitable alternative will be run to show fluid was placed in the proposed interval.

(vv) On completion of the work, the applicant must file a Sundry Notice (Form 4), summarizing the disposal operation.

(ww) The Commission or its staff may designate conditions other than those listed in this rule as it deems necessary to ensure safe disposal of these fluids. The application shall be approved if the application for a permit is complete and if water in the proposed interval has total dissolved solids in excess of 10,000 milligrams per liter and fresh water or Underground Sources of Drinking Water will not be influenced by the disposal operation.

Section 12. Aquifer Exemption

(a) An aquifer which contains fresh and potable water may be exempt from the definition in Chapter 1, Section 2 (a), if the Commission by order, after due and legal notice and public hearing, determines any of the following criteria exists:

(i) it is mineral, hydrocarbon, or geothermal energy producing;

(ii) it is situated at a depth or location which makes recovery of fresh and potable water economically or technologically impractical;

(iii) it is so contaminated that it would be economically or technologically impractical to render the water fit for use as fresh and potable water;

(iv) it is located over a mining area subject to subsidence or catastrophic collapse; or

(v) it has a total dissolved solids (TDS) of more than 5,000 and less than 10,000 milligrams per liter (mg/l) and is not reasonably expected to be used as fresh or potable water.

(b) Interested parties wishing to have an aquifer exempted must submit to the Commission an application which includes sufficient data to justify the proposal. At a minimum a structure or isopach map, geologic description, and legal description of the area to be exempt needs to be filed. The Commission will provide thirty (30) days legal notice prior to a public hearing on the matter.