5/1/2014

CLASS II UNDERGROUND INJECTION CONTROL (UIC) PEER REVIEW- SMALL PROGRAM

Names of Agencies
and
Date(s) of Review

GROUND WATER PROTECTION COUNCIL
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The Class II UIC Program Peer Review

Preface

The Ground Water Protection Council (GWPC) initiated the Class II Underground Injection Control (UIC) Program Peer Review process in 1989 as part of the Association's effort to assist states in development and implementation of effective Class II UIC regulatory programs subsequent to passage of the Safe Drinking Water Act (SDWA) in 1974 and promulgation of federal rules in 1980. The peer review process provides an in-depth evaluation of state Class II UIC programs using a detailed questionnaire and direct interviews conducted by a team of experienced Class II UIC program directors (peers) and GWPC staff at a host-state. The GWPC invites representatives of the United States Environmental Protection Agency (EPA) and the United States Department of Energy (DOE) to participate as observers.

The purposes of the Class II Peer Review are as follows:

1. Provide a tool for evaluating the effectiveness of Class II UIC programs in protecting Underground Sources of Drinking Water (USDWs);
2. Promote information exchange between state programs by documenting how reviewed states and direct implementation programs address shared program issues and challenges;
3. Identify evolutionary program enhancements implemented since Class II UIC programs were first granted primacy by the EPA, or improvements implemented by direct implementation programs administered by EPA;
4. Assist the states and GWPC in identifying potential problem areas;
5. Provide states an independent evaluation of their Class II UIC program including non-binding recommendations for program improvements; and
6. Evaluate Class II UIC program responses to emerging issues.

Chartered in 1983, the GWPC is a nonprofit organization whose members consist of state groundwater and UIC regulatory agencies dedicated to the protection of the nation's groundwater supplies. The GWPC is the only national association whose members regulate UIC wells. The GWPC strives to promote the use of best practices and effective regulations based on sound science. The mission of the GWPC is to… "promote protection and conservation of groundwater resources for all beneficial uses, recognizing groundwater as a critical component of the ecosystem". The GWPC provides a forum for stakeholder communication and research to improve government's role in the protection and conservation of groundwater.

The GWPC Board of Directors is composed of 24 senior state program directors elected by their peers from each of the ten USEPA regions. Board members are the highest ranking, non-elected/non-appointed, senior program managers over groundwater, source water and/or UIC programs. Board members typically have advanced degrees in geology, engineering, or other applied sciences that enable them to grapple with the technical complexities involved with underground injection and effective groundwater protection.

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Scope of the Class II Peer Review

The Class II UIC Program Peer Review is designed to assist states in evaluating and improving their Class II injection well regulatory programs. The wellbore is the focus of the UIC Program regulations under the Safe Drinking Water Act. Therefore, the Class II Program Peer Review questionnaire and interview process were designed to evaluate regulatory elements pertaining to the subsurface wellbore, from the wellhead down through the injection zone.

The questionnaire probes the authority, standards, and regulatory practices pertaining to the wellbore, including:

- Well design standards that are evaluated during the permitting process;
- Assessment of the other wellbores proximal to the proposed injection well that potentially could provide an avenue for fluid migration;
- Well construction standards;
- Criteria for verifying wellbore mechanical integrity prior to injection;
- Mechanical integrity, monitoring, and testing standards during injection operations; and
- Proper plugging and wellbore closure.

In addition to evaluating the technical standards that are applicable to each wellbore, the questionnaire assesses how each state applies regulatory tools to provide groundwater protection, including:

- Public outreach and input practices;
- Permit requirements and evaluation processes;
- Inspections;
- Compliance and enforcement procedures;
- Submittal of records and monitoring results;
- Data management systems; and
- Ancillary effects of underground injection.

The Class II UIC Program Peer Review does not address other important aspects of waste segregation, storage, or management at oil and gas production facilities, transportation of wastes to the Class II facility, or treatment and storage of fluids at the Class II facility prior to injection. Furthermore, this Peer Review does not address management or disposal of Naturally Occurring Radioactive Materials (NORM) that may be present in some produced waters above background levels or above regulatory thresholds. These surface waste management practices are addressed through another state review process managed by a multi-stakeholder organization called State Review of Oil and Natural Gas Environment Regulations, Inc. (STRONGER). Collectively, these two state review process address the full-spectrum of practices associated with the safe and responsible management of oil-field waste byproducts from generation through their disposal.

The Class II UIC Program Peer Review was revised in 2013 to include questions pertaining to several emerging issues including; induced seismicity and hydraulic fracturing. Even before passage of the SDWA, it was well known that injecting fluids into the earth in some

geologic settings and under specific conditions had the potential to cause seismic events. A seismic event attributed to human activity is called "induced seismicity". Over 170,000 Class II injection wells have been operating over the past three decades. During this same period, produced water injection has been identified as the suspected or likely cause of induced seismicity at eight sites, less than .005 percent of total sites nationwide. These induced seismic events did not result in loss of life or significant property damage. However, the events were felt and reported by area residents and have raised questions regarding the adequacy of current monitoring and precautionary measures.[1] Industry experts as well as federal and state officials are actively examining this issue to determine if best practices and regulatory enhancements can improve prevention. Therefore the GWPC has added questions to probe state experience with induced seismicity.

In 2005, Congress passed the Energy Policy Act, clarifying the original intent of the SDWA, and thereby distinguishing hydraulic fracturing related to oil, natural gas, or geothermal operations from the practice of underground injection. However, Congress stipulated that hydraulic fracturing with diesel fuels should be regulated as underground injection. In 2013, EPA released draft guidance regarding the permitting of wells that will be hydraulically fractured using diesel fuels. While Congress recognized that hydraulic fracturing of oil and gas reservoir is not underground injection as defined by the SDWA, states continue to regulate the practice under oil and gas conservation and environmental protection statutes. As a result of these regulatory and guidance developments, the GWPC has added questions to the Class II UIC Program Peer Review to explore agency response to EPA's draft guidance.

Finally, the GWPC has added questions that probe the bottom line of injection practice after 30 years or more of Class II UIC Program implementation under the SDWA by asking:

- How effective has the program been in protecting groundwater resources;
- What groundwater incidents or issues have been identified;
- What role has injection played in improving groundwater protection compared to alternative waste management and disposal practices?

Because there are risks associated with any method of waste disposal, Class II UIC programs continue to evaluate the results of groundwater monitoring as well as the findings of investigations in response to citizen complaints. When groundwater quality issues are found proximal to Class II injection facilities, agency investigators evaluate evidence to determine causation. When those findings link injection to degraded groundwater quality, this Peer Review probes how have those findings have shaped programmatic or policy revisions and regulatory enhancements.

[1] The National Committee on Induced Seismicity, 2012, Induced Seismicity Potential in Energy Technologies.

Introduction: UIC Program

Underground injection is the placement of fluids, including but not limited to waste by-products, into the subsurface through a wellbore. Underground injection is not a new practice. The Chinese injected freshwater for salt extraction as early as A.D. 300. The first documented use of injection to dispose oilfield produced water (brine) was in Texas during the 1930s, over eighty years ago. Beginning in the 1930s, the oil and gas industry also began to inject produced water into pressure-depleted oil reservoirs in order to enhance recovery of crude oil resources. During the 1970s and 80s, oil refineries and chemical industries began to inject liquid wastes in deep disposal wells. Today, underground injection is used to remove more than 50 percent of the liquid hazardous waste, and more than 98 percent of salt water produced by onshore oil and gas operations from the surface environment[2].

Some waste is an unavoidable by-product of a myriad of resource development and manufacturing processes that create thousands of products that we use in our daily lives including: steel, plastics, pharmaceuticals, fuels, and natural gas. Underground injection is an important waste management practice internationally and in the United States. Some renewable energy sources, such as geothermal, also rely on underground injection. Municipalities need underground injection to replenish aquifers (aquifer storage and recovery), combat saline water encroachment in coastal areas, to dispose of residual waste streams generated by treatment and desalination of water for public use, and to dispose treated sewage. While industries continue to develop ways to reduce waste volumes and recycle, generated wastes must be disposed in a safe manner. Various types of injection wells have unique associated benefits and risks. To dispose fluids safely, injection wells must be properly constructed, located in an appropriate geologic setting, operated, maintained and monitored in accordance with standards that are protective of our groundwater resources.

Liquid wastes can be managed in a variety of ways other than underground injection including: 1) treatment and release into surface waters, such as rivers, through a National Pollutant Discharge Elimination System (NPDES) permit issued pursuant to the federal Clean Water Act, 2) biological treatment, 3) incineration, 4) storage in evaporation pits, 5) discharge into percolation pits, and 6) beneficial re-use (e.g., irrigation, livestock watering, ice or dust control). Each of these practices has its limitations and associated environmental risks. For many waste streams, including produced water generated during oil and gas exploration practices, the volumes are too great to rely solely on these alternative waste management practices. Furthermore, injecting highly saline fluids back into deep subsurface reservoirs that contain equally saline water is a common-sense waste management practice that poses fewer environmental or public health risks than these alternatives.

Underground injection plays a crucial role in disposing residual wastes, especially those that would pose the greatest risks to society if managed by any other method, such as discharge to surface waters. In other words, if underground injection is restricted or eliminated, the result will be more, not less risk of environmental harm.

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[2] Van Voorhees, R. F., Bryan Cave LLP, 2001, Removed from the *Environment, The Environmental Forum, The Policy Journal* of the Environmental Law Institute, Vol. 18, Number 2.

In 1974, Congress passed the Safe Drinking Water Act (SDWA), which required the U.S. Environmental Protection Agency (U.S.EPA) to develop minimum federal requirements for injection practices. Regulations adopted pursuant to the SDWA are now administered by U.S.EPA along with state and tribal partners that collectively constitute the UIC Program. The purpose of the UIC Program is to protect public health by preventing contamination of underground sources of drinking water (USDWs).

A USDW is defined as an "aquifer or its portion which supplies any public water system or contains a sufficient quantity of groundwater to supply a public water system, and either currently supplies a public water system, or contains less than 10,000 milligrams per liter of total dissolved solids and is not an exempted aquifer."[3] Most groundwater used for public drinking water today contains less than 500 milligrams per liter of Total Dissolved Solids (TDS),and most water that is treated for drinking water contains less than 3,000 milligrams per liter TDS. Therefore, the UIC Program ensures that water resources that could be treated and used as drinking water in the future are protected today.

After passage of the Safe Drinking Water Act (1974), U.S.EPA worked with a twelve-member state workgroup to develop the UIC Program rules (1976-1977). From the onset of rule development, regulatory officials sought to apply lessons learned from decades of injection experience. Prior to enactment of the federal regulations, U.S.EPA and state officials examined best practices as well as problems associated with injection well operations that pre-dated passage of the SDWA.

While developing the UIC Program regulatory framework, U.S.EPA and state officials recognized six pathways through which injected fluids could potentially migrate into USDWs. Officials sought to develop regulatory standards that mitigate and effectively address the following pathways:

- Migration of fluids through a faulty injection well casing;
- Migration of fluids through the annulus located between the casing and wellbore;
- Migration of fluids from an injection zone through the confining strata;
- Vertical migration of fluids through proximal, improperly abandoned, or improperly completed wells that penetrate the injection zone;
- Lateral migration of fluids from within an injection zone into a protected portion of that stratum; and
- Direct injection of fluids into or above an USDW[4].

The U.S.EPA has defined six classes of injection wells that are permitted and regulated under the SDWA, which are summarized in the following chart.

[3] U.S. Environmental Protection Agency, 2002, Definition: *Underground Source of Drinking Water* (Section 146.3 of Part 146); U.S. Code of Federal Regulations, Title 40, Part 146, revised of July 1, 2002.

[4] Osbourne, P., 2001, Technical Program Overview: *Underground Injection Control Regulations*, Office of Water 4606, EPA 816-R-02-025.

Injection Well Classification Chart

U.S.EPA Classification	Injection Well Description	Active Inventory
CLASS I	Wells used to inject waste beneath the lowermost USDW	523[5]
CLASS II	Wells used to dispose of fluids associated with the production of oil and natural gas	144,000[6]
CLASS III	Wells used to inject fluids for the extraction of minerals	19,925[7]
CLASS IV	Wells used to dispose of hazardous or radioactive wastes into or above a USDW	540
CLASS V	Wells not included in the other classes generally used to inject non-hazardous waste	650,000-1.5 Mil.[8]
CLASS VI	Wells used to geologically sequester carbon dioxide to reduce greenhouse gas emissions	N/A

The U.S.EPA is charged with enforcement of the SDWA, and exercises that authority directly or through formal agreements with state and tribal partners, under their oversight. The U.S.EPA has given primary enforcement authority, called ***Primacy***, over underground injection wells to those state agencies or tribes that have shown they are able to implement a UIC Program that is effective in protecting groundwater resources. These requirements are in Sections 1422 and 1425 of the SDWA, and the Federal Register (40 Code of Federal Regulations Sections 144 through 147). The states that U.S.EPA has determined have regulations, laws, and resources in place that meet the federal requirements and are authorized to run the UIC Program, are referred to as ***Primacy states***. Primacy states manage their programs subject to periodic audits and program reviews conducted by U.S.EPA. In states that have not received primary enforcement responsibility for the UIC Program, U.S.EPA remains the responsible regulatory agency. These states are referred to as ***Direct Implementation (or DI) states***, because U.S.EPA directly implements the federal UIC regulations in these states. Some states share responsibility with the U.S.EPA, with authority over some well classes residing at the state level, and other well classes being regulated by U.S.EPA.

[5] Source: GWPC, Class I Inventory of the United States prepared by the Ground Water Protection Council., September, 2007.

[6] Source: U.S.EPA http://water.epa.gov/type/groundwater/uic/class2/index.cfm

[7] Source: GWPC Class III Well Inventory prepared by Subsurface Technology, Inc., January 2004

[8] Source: GWPC, This number is based on a state-by-state estimate of Class V wells and is expected to increase when an inventory is conducted.

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The Class II UIC Program

Class II injection wells are used primarily to inject fluids that are associated with oil and gas exploration and production (E&P) activities including drilling, stimulation (hydraulic fracturing), and production operations. Since the inception of oil and gas exploration and development (1860), the oil and gas industry has been generating and managing produced water. Produced water is the water extracted from the subsurface during oil and gas E&P activities. Produced water occurs naturally within underground formations, and is brought to surface along with oil and gas through a cased wellbore.

Produced water is generated 1) while drilling through saline water zones that naturally occur in the subsurface and overlie the target oil and gas reservoir(s), 2) after stimulation of oil or gas reservoirs by hydraulic fracturing during the flow back and swabbing processes, 3) during work-over operations, and 4) during day-to-day production operations. Long before hydraulic fracturing operations started in the 1940's, the oil and gas industry generated large volumes of produced water that was capable of harming the environment if not properly managed.

Produced water characteristics and physical properties vary considerably depending on the geographic location of the field, the geological formation with which the produced water has been in contact for thousands of years, and the type of hydrocarbon product being produced. Produced water properties and volumes can even vary throughout the lifetime of an oil and gas well or reservoir. Produced waters can be highly saline, with salt concentrations exceeding 200,000 milligrams per liter of chloride (more than ten times as salty as sea water) or may be pure enough for agricultural or irrigation purposes. In addition, produced water commonly contains many organic and inorganic compounds that can lead to toxicity. Some of these are naturally occurring dissolved or emulsified hydrocarbons derived from associated crude oil while others are related to chemicals that have been added for well-control or reservoir stimulation purposes. These fluid wastes are specifically excluded from hazardous waste classification under the Resource Conservation and Recovery Act (RCRA).[9]

The 1980 amendments to the RCRA required U.S.EPA to conduct a study of the environmental and potential human health impacts associated with E&P wastes and their associated waste management practices. U.S.EPA completed its two-year study in 1987. Based on the findings in the Report to Congress, and on oral and written comments received during public hearings in the spring of 1988, on June 30, 1988, U.S.EPA decided not to recommend federal regulation of E&P wastes as hazardous wastes under Subtitle C of RCRA (U.S.EPA 1988). This determination is commonly referred to as the "RCRA exemption". Although produced water is exempt from one section of RCRA, it is subject to requirements in RCRA Subtitle D and the Safe Drinking Water Act.

Approximately 20 billion barrels (bbl.) of produced water are generated by federal and state onshore operations in 2007. Generally, the volume of produced water from oil wells does not remain constant over time. The water-to-oil ratio can increase over the life of a conventional oil well. For such wells, water makes up a small percentage of produced fluids

[9] Veil, J.A., M.G. Puder, D. Elock, R.J. Redusik, 2004, A White Paper describing Produced Water from Production of Crude Oil, Natural Gas, and Coal Bed Methane, prepared by Argonne National Laboratory, prepared for the U.S. Department of Energy, 79 pp.

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when the well is new. Over time, the percentage of water increases and the percentage of crude oil declines. On average, more than 7 bbl. of water are produced for each barrel of oil. For crude oil wells nearing the end of their productive lives, water can comprise as much as 98% of the fluid brought to the surface.[9]

On the other hand, most shale gas wells generate most of their produced water after hydraulic fracturing operations are completed and pumping pressure is relieved from well. During the flow back process, water-based fracturing fluid mixed with natural formation (connate) water begins to flow back to surface. The majority of produced water recovered from typical shale gas operations is recovered during the first several months after completion.[10]

Produced water is separated from crude oil or natural gas at the surface facility associated with producing oil and gas wells. It is delivered to Class II injection well facilities by pipeline or truck. Once delivered to the storage facility at the injection well, any remaining crude oil is skimmed, the water may be filtered to remove solids such as sand or silt, and the water may undergo other types of treatment prior to injection

Today there are approximately 144,000 Class II injection wells operating in 31 states. There are three types of Class II injection wells:

- Hydrocarbon storage wells;
- Enhanced oil recovery wells; and,
- Produced water disposal wells.

Hydrocarbon storage wells are used to pump crude oil and other liquid hydrocarbons beneath underground salt deposits for temporary storage, prior to recovery, processing and use. Enhanced oil recovery (EOR) wells are used to prolong the productive life of oil wells within a specific oil field. Secondary recovery is an EOR process commonly referred to as water-flooding. Salty water produced with oil is separated from the oil at surface and re-injected in the oil-producing formation to drive oil to proximal, pumping oil wells completed in the same reservoir. This saline waste-water by-product is referred to as "produced water" or "salt water" because salts (sodium, calcium, magnesium, potassium chlorides) are the predominant dissolved constituents in produced water. Produced water disposal wells are sometimes referred to as "salt water disposal wells" because they inject fluids into deep saline reservoirs for disposal purposes. Nationally, approximately 60 percent of all salt water produced with onshore oil production wells is re-injected at Class II EOR wells, while 40 percent is injected for disposal.

As of 2012, U.S.EPA has awarded primacy for the Class II Program to 42 states and territories and two tribes. The following map shows the distribution of Primacy states and Direct Implementation states.

Class II injection well regulations establish standards that address the six potential pathways in the following manner:

- Prior to issuance of a permit, geologists evaluate the suitability of a proposed site for injection. As part of the permit review process, geologists determine the depth of the

[10] Ground Water Protection Council and ALL Consulting, 2009, *Modern Shale Gas Development in the United States*, a Primer, prepared for the United States Department of Energy, 98 pp., Web 1, March, 2011.

deepest USDW, evaluate the adequacy of the proposed injection zone, and examine the thickness and nature of confining strata on a site specific basis.

- Permit writers establish the depth of surface casing necessary to extend through and isolate all USDWs.
- In addition to cemented surface casing, Class II injection wells must be constructed with multiple layers of protection (cemented, steel casing strings) between USDWs and the injected waste stream. Most Class II injection wells have four-to-six layers of protection between the injected fluid and the protected groundwater. Therefore, injected fluids can only enter USDWs as a result of faulty casing when there are multiple, concurrent failures of cemented, steel casing strings.
- Regulators establish injection pressure limits designed to confine injected fluids in the authorized injection zone.
- The mechanical integrity of casing and injection tubing are tested prior to commencement of injection operations and monitored on a regular, scheduled basis thereafter. Mechanical integrity tests must be conducted at least every five years, and more frequent tests may be required by rule or permit condition.
- All known wellbores that penetrate the proposed injection zone are evaluated within an "Area of Review" surrounding the proposed injection well. Wellbores that pose potential avenues for fluid migration by virtue of their construction or plugging status must be mitigated before injection can be authorized.
- Injection owners must monitor their operations and submit reports regarding injection pressures and fluid volumes.

Produced water is injected into depleted oil and gas reservoirs or deep reservoirs that are naturally saline. These saline reservoirs contain water with similar in chemistry to the injected produced water. Typically, produced water is injected into porous and permeable sandstone or dolomite formations that are overlain by "confining strata".

Confining units consist of rock types that typically have low permeability, such as shale, halite (salt), anhydrite, and some limestone formations. When confining units overlie oil and gas reservoirs, they are also referred to as "cap rocks" because the strata have effectively sealed oil, natural gas and even CO_2 in the underlying reservoir for millions of years with no, or minimal, leakage. The effectiveness of confining units has been further validated through extensive stratigraphic tests, and decades of successful experience at gas storage and injection operations.

Constructing a wellbore and maintaining mechanical integrity throughout injection operations is a key principal of injection well regulations. An injection well is said to have "mechanical integrity" if: 1) there are no significant leaks in the casing, including injection tubing (the string of steel pipe through which fluids are actually injected), and 2) there is no significant fluid movement behind casing (either behind cement or in un-cemented annular spaces) into a USDW. Class II regulations require operators to construct a well in a manner that mechanical integrity can be tested and monitored.

Class II injection wells are constructed with multiple layers of protective, cemented casing to isolate USDWs from the injected fluid much like double-hulled vessels or underground storage tanks. Class II injection wells also feature an early warning leak-detection system that is easily monitored at surface to enable quick detection of mechanical integrity issues by the operator or regulatory inspector. This early warning system is created by installing injection

tubing inside the smallest diameter cemented casing and setting it above the injection zone on a packer, a mechanical device with expandable rubber components that are activated to create a liquid tight seal between the tubing and casing. The annular space between the casing and tubing is then filled with water containing a corrosion inhibiter from the top of the packer to surface where it is confined by a valve with a pressure gauge. This sealed, water-filled annular space can be pressure tested to detect leakage, and can be monitored over time for pressure changes. Even small volumes of leakage through the tubing or at the packer will result in an immediate pressure increase that is readily detected at surface by reading the pressure gauge. This is a basic application of Pascal's Law which states that "Pressure applied to fluids filling a sealed vessel will persist." When pressure readings signal a potential integrity problem, injection ceases and the operator is required to perform diagnostic and corrective actions. The vast majority of detected mechanical integrity problems are caused by deterioration of the packer seal or corrosion of the injection tubing. When such mechanical integrity losses are detected, multiple layers of protection remain intact to prevent injected waste from entering drinking water supplies. When mechanical integrity problems are corrected, the operator must pass a new test to verify mechanical integrity before injection operations can resume.

Injection well operators are required to verify that each Class II well has mechanical integrity before commencement of injection is approved; at least every five years thereafter; and every time down hole equipment, such as injection tubing or packer, is removed for servicing or repair. These standards are enforced to protect USDWs and ensure that fluids are injected into the authorized injection zone.

Over the years, some have questioned the advisability and safety of injecting fluids underground. While every waste management practice has associated risk, alternatives to underground injection inherently pose greater risk because of their proximity to the near surface environment. The value and effectiveness of Class II injection is best appreciated when viewed in the context of historic waste management practices and their associated environmental impacts. In some states, historic practices such as disposal in unlined pits or surface discharge resulted in widespread ground and surface water contamination, scalded soils, and crop and vegetation damage. As underground injection became the preferred method of disposal, the success of the UIC program could be measured in the dramatic reduction in environmental damage. If the success of a regulatory program is measured in the prevention of environmental harm, the UIC program should be respected as a highly successful environmental program.

5/1/2014

Questionnaire

PART I: GENERAL UNDERGROUND INJECTION CONTROL PROGRAM FRAMEWORK

A. Statutory Authorities and Regulatory Jurisdictions

1. Please include a copy, citation, or link for all statutes, rules, regulations, policies, procedures, and orders applicable to the injection of Class II eligible wastes for disposal, enhanced oil recovery project, and hydrocarbon storage.

2. What is the statutory authority upon which your UIC program is based?

3. Does this statutory authority include promulgation of rules and other regulatory tools? Describe and cite the enabling authority.

4. What year did U.S.EPA grant primary authority to your agency for permitting and regulating Class II injection?

5. Do statutes or rules pertaining to injection and protection of waters of the State contain definitions of "injection", "enhanced oil recovery", other types of "disposal wells", "hydraulic fracturing", "protected groundwater" (e.g. fresh and/or usable water), and "USDW's" (Underground Sources of Drinking Water)? Yes/No

   Provide citations and definitions for these terms.

B. Program Administration

1. Attach an agency organizational chart and identify UIC positions in administration, permitting and file review, inspections, mechanical integrity testing, compliance and enforcement, data management and public outreach. Indicate the approximate percent of time dedicated to the UIC program per listed employees on an annual basis.

C. Staffing and Funding

1. Please provide funding levels and the total staff complement for the agency or division of agency (if applicable) UIC and non-UIC functions.

2. What does your program accomplish that could not be accomplished if funding was restricted to the federal grant and the obligatory (25%) state match?

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3. Are the levels of funding and staff provided adequate to accomplish UIC program goals, objectives, and performance measures established through the grant, and your strategic planning or goal-setting process?

4. What sources of state funding does the agency use to support the UIC Program?

D. Data Management Program for the Agency

1. Describe the software and hardware used to manage UIC program data (e.g., SQL server, RBDMS, Oracle).

2. Is the data management system capable of auto-generating periodic reports, letters, notices and forms such as Form 7520, as required by U.S.EPA? Yes/No

3. Does the UIC data management system integrate and share data with oil and gas data management systems? Yes/No. Please describe

E. Interagency Coordination

1. Please provide or summarize any memoranda of agreements or similar agreements between state agencies, or between the state and any other governmental entities (BLM, US Fish and Wildlife Service, EPA, Indian Tribes, local jurisdictions and water management districts) which relate to coordination of UIC regulation, sharing of information, or response to complaints, if applicable.
Attached? Yes/No (attachment identifier)

F. Changes in General Activities since Primacy

1. Excluding the changes in data management that are described in Section I-D and throughout the remaining sections, what significant changes have occurred within the agency or outside the agency that have affected the administration of the UIC program such as new statutes or significant regulatory changes?
Attached? Yes/No (attachment identifier)

2. Has the Congressional passage of the Safe Drinking Water Act Reauthorization (1996) or other federal mandates caused changes in the way the UIC program is administered (i.e. Wellhead protection, Source Water Protection, Watershed Management etc.)? Yes/No
If yes, describe the changes.

3. Has the SARA Title III Program of EPA and the Community Right -to Know Program (EPCRA) had an impact on your UIC program or on the ability of the regulated community to meet deadlines established in the State UIC regulations? Yes/No
If yes, describe the impact.

PART II: PERMITTING/COMPLIANCE REVIEW

A. Permit Application Flow and Review Process

1. How does the Operator initiate a permit application?

   Who receives the application from the Operator?

2. How and by whom are permit applications screened for completeness?

   What are the required elements of a complete application?

   What is the procedure used when an application is found to be incomplete?

3. How long is the Operator given to reply in the case of an incomplete application before it is considered null and void, or denied, and how is the Operator notified?

4. In the case of voided or denied applications, is the application returned to the Operator or kept by the reviewing agency?

5. Upon a determination of application completeness, how is it routed for further evaluation?

6. Who are the individuals responsible for reviewing the different aspects of the permit application? Technical Issues? Administrative Issues?

7. Does the permit review process, include a site-review prior to determination? If yes, what factors are evaluated in the site review?

8. How is an application tracked to ensure that both review and permit issuance/denial recommendation occurs in a timely manner?

9. Is the process described under questions 1-8 the same or different for applications to amend existing permits? (Existing in the sense the permit for which amendment is sought is active.)

Is the process flow different for major versus minor amendments? Yes/No

If yes, how does the agency differentiate major and minor amendments?

For major permit modifications, does the agency require a new public notice? Yes/No

10. How are UIC applications for commercial disposal wells processed differently, if at all?

11. How are the official copies of the permits stored and protected from loss?

12. Does the agency allow a well to be used for the disposal of both Class I and Class II fluids? Yes/No

    Under what circumstances?

    If Yes, how are these wells permitted and which agency acts as the principle in processing the permit, soliciting and responding to public input, holding hearings, and rendering a permit determination?

B. Technical Aspects of the Permit Review Process

1. How does the agency determine the depth of the deepest USDW?

   Does the state collect and maintain records and data, and/or prepare maps regarding the depth and quality of groundwater in aquifers that are designated as USDWs. Yes/No

   If yes, what agency(ies) are responsible for identifying and determining the basal elevation of USDWs?

2. Are USDW records, data and maps available to the regulated industry? Yes/No

   How does the agency ensure that records, data, and maps are factored into the well design or permitting process so that USDWs are effectively isolated and protected?

3. Are there areas of the state where Class II injection is practiced, where USDWs are undefined or unmapped? Yes/No

   If yes, how does the agency ensure identification and protection of protected groundwater, including USDWs in such areas?
   Attached? Yes/No (attachment identifier)

4. What is the regulatory framework (statute, rules, field orders, permit conditions, approved work plans, etc.) to ensure that new wells are constructed in a manner that is protective of USDWs?

5. Are casing and cementing plans reviewed and approved prior to well construction?

6. What is the minimum depth that surface casing, or the water-protection string must extend below the base of the deepest USDW?

   Does the agency provide an alternative construction method for new wells besides setting surface casing through the deepest USDW? Yes/No

   If yes, describe the alternative construction method and how USDW protection is accomplished.

7. Are the construction standards for converted well different than for new wells?

   If yes, is casing required to be set and cemented through all USDW's?

8. Are dual completions accepted?

   What types?

9. How are the maximum injection pressures and rates established?

10. Can the operator request modification of approved injection pressures or rates? Yes/No

    If yes, what information must the operator provide to justify an increase in the approved injection pressure or rate?

11. Has the compatibility of injectant/cement and injectant/formation fluid been a problem? Yes/No

    If yes, describe the nature and extent of the problem(s).

12. Does the agency require the Applicant to provide an analysis of the produced waters that will be injected at the proposed well? Yes/No

    If yes, what parameters must be included in the analysis?

    If no, how does the agency determine the compatibility of the injectate to the injection zone?

13. Are the technical permit review processes and/or standards different for commercial injection wells? Yes/No

    If yes, describe or list those differences.

C. Area of Review Considerations and Procedures

1. How is the Area of Review determined for enhanced recovery wells or projects? For disposal wells? For commercial wells?
2. If area permits are issued, how is their area of review determined?

   Is the Operator's application denied if he/she has no legal status to effect corrective action to wells in the AOR that require such action?

3. What criteria does the agency use to evaluate the adequacy of a plug job for wells that penetrate the injection zone within the area of review?

D. Induced Seismicity Considerations

1. Are Class II injection wells permitted in areas of your state that have a history of seismic activity? Yes/No If yes, explain why.

2. Has the agency concluded based upon credible, scientific evidence that seismic events with a magnitude equal to or greater than 4.0 (Richter Scale) have been linked to Class II injection operations in your state?

   If the answer to Question #2 is "No", the remaining questions in Part II, Section D are optional.

3. How many operations have been linked to induced seismicity?

   What was the highest recorded magnitude of an induced seismic event (Richter Scale)?

   Were there any personal injuries or documented property damage associated with induced seismic events?

4. If the agency has made such a determination, have findings and conclusions been documented within a report? Yes/No

   Is the report available to the public?
   Attached? Yes/No (attachment identifier)

5. What enforcement actions have been initiated on the basis of agency findings and conclusions pertaining to induced seismicity?

6. Were the documented seismic events associated with Class II disposal, water flooding, or other secondary or tertiary recovery operations?

7. What is the agency process for investigating seismic events in the vicinity of Class II injection operations?

   Does the agency coordinate such investigations with other agencies/entities that monitor seismic activity?

   If yes, what agencies and/or entities, and what is their role in the investigation process?

8. Has the agency identified factors (structural features, location, depth, injection zone, injection pressure, rate, or other operational factors) that may have contributed to induced seismicity? Yes/No

   If yes, has the agency implemented a screening process to evaluate potential hazards relative to these factors?

9. Does the state have an agency that is responsible for mapping faults and/or monitoring seismic events? Yes/No

   If yes, who is the agency, and describe the current state of mapping and monitoring activity.

   How does the Class II Program coordinate activities and share information with this agency?

10. Were the documented seismic events associated with Class II wells that penetrate the surface of the Pre-Cambrian basement, or inject fluids into a reservoir directly overlying basement rocks? Yes/No

11. How many and what percent of the state's Class II wells penetrate the surface of the Pre-Cambrian basement or inject fluids into a reservoir directly overlying basement rocks?

12. Does the agency require seismic monitoring near some or all Class II injection wells? Yes/No

    If yes, explain your criteria for selecting sites for monitoring and your monitoring program.

13. Does the agency require additional types of testing or logging at sites that may pose greater seismic risk? (e.g., fall-off tests, spinner surveys, step-rate tests, radioactive tracer tests, dipole sonic logs, resistivity logs, etc.)? Yes/No

14. Does the agency require more detailed assessment of reservoir properties at sites that may pose greater seismic risk? (e.g. pore pressure, permeability, breakdown pressure, Instantaneous Shut-In Pressure, lithostatic pressure, hydrostatic pressure, horizontal stress magnitudes and azimuth)? Yes/No If yes, describe.

15. Has the agency amended statutes, rules, or permitting requirements in order to reduce induced seismicity hazards (e.g., enhanced monitoring and modulation of injection pressure and/or rates)? Yes/No If yes, describe those amendments.

E. Administrative Aspects of Permit Application Review

1. Prior to permit determination, what are the public notification requirements?

2. How are public comments related to the proposed permit or application recorded and filed?

   Is the same filing process used for complaints, which are submitted to the agency after UIC approval has been given?

3. When does the public comment period start (upon determination of completeness, or after completion of technical review)?

4. When and where are public hearings held on an application?

5. How are the public hearings conducted? (formal, informal, transcript, qualifications etc.)

   How is public input documented?

   How are public comments and questions addressed during and/or after the public hearing?

6. What criteria, conditions or circumstances would prompt a public hearing on an application?

7. In reference to hearing participation, does the agency have a definition for "significant interest" necessary to trigger a public hearing?

8. Are there other state or local government agencies that participate in the permit review process? Yes/No

   If yes, what are their specific roles in the review process?

9. What types of financial assurance mechanisms (bonding, insurance, etc.) are required for UIC applications?

   How is coverage per well determined?

10. In reference to question #9, under what conditions is blanket surety coverage allowed?

F. Aquifer Exemptions

1. Are aquifer exemptions allowed and if so what criteria were used to support the request? Attached? Yes/No (attachment identifier)

G. Data Management Systems Used in Permit Application Review

Describe the data management system (s) used in the various components of the Permitting/File Review process as set forth in Section A-F. The description should delineate both the systems used for technical and administrative activities.

1. When were the data management systems currently in use first put into operation?

2. Can Operators file some or all documentation pertaining to application submission electronically?

   Does the system electronically track and route the permit application to the appropriate staff?

   Does the system allow the operator to view permit status online? Describe.

3. Is the agency's data management system locally housed (intramural) or linked with other state databases?

H. Periodic File Review Process

1. How are wells selected for file review?

Is the compliance history a factor of selection? Yes/No

What are the elements of a file review?

2. Over a year period, what percentage of total UIC permits receives a file review?

3. When deficiencies are discovered during the review, what actions are taken to correct the deficiency?

I. Changes and Modifications to Program since Primacy

1. Exclusive of the changes in data management described under Section G., what statutory, regulatory or policy changes have occurred since receiving primacy in the UIC Permitting/File Review process? Please list or explain.

PART III: WELL CONSTRUCTION

A. Casing, Tubing, and Downhole Equipment Standards

1. Describe or provide a schematic(s) showing typical construction practice for a new Class II injection well including casing, tubing, cement and packer as well as the base of the deepest USDW and injection zone.

2. Are packers routinely required for all newly completed and converted wells? If there are exceptions, what are the criteria used?

   Does an exception impose alternative requirements (i.e., more frequent MITs, annulus and pressure monitoring, limitation on injection volume)?

3. Do regulations or permits specify the type of packer to be used?

4. Do regulations or permits specify the use of tubing?

5. Does the agency allow injection directly through casing without a packer and tubing? If yes, under what circumstances and conditions?

6. Does the agency allow injection through tubing with a packer set within the water protection string?

   If yes, under what circumstances and conditions?

   Are dual completions accepted? What types?

7. At the time primacy was approved, were existing injection wells "grandfathered" into the Class II Program? Yes/No

   a. Do grandfathered wells meet current well construction standards? Yes/No

      If no, please describe those differences and how the agency ensures protection of USDWs.

B. Cementing Standards

1. Does the agency require that casing set through USDWs be cemented to surface? If not, how are USDWs otherwise protected?

2. Does the agency have a standard for the minimum height of cement above the permitted injection zone?

   If not, how are injected wastes otherwise confined to the permitted injection zone?

3. How does the agency evaluate the quality and effectiveness of casing cement jobs?

4. Does the agency have authority to require testing or evaluation of cement jobs? Yes/No

   If yes, under what circumstances and what types of tests or evaluations are required?

   What actions does the agency take if such evaluations indicate that the well does not meet current construction standards?

C. Well Construction Inspections

1. During the drilling and well construction process is the operator required to notify the agency prior to commencing specific activities? Yes/No If yes, list those activities.

D. Data Management for Well Construction Operations

1. What records does the agency require Operators to submit to document well construction practices and wellbore integrity?

2. Does the agency require submittal of all geophysical logs, and cement evaluation logs that have been run? Yes/No

   Are such logs stored electronically or in hard copy, or both?

3. Can the data management system generate wellbore schematics electronically based upon submitted construction information? Yes/No

PART IV: INSPECTIONS

A. Management of Inspections

1. Who coordinates and manages the work of the inspectors and at what level does this supervision take place (central office, district office, field supervisor working out of home)?

2. Do the inspectors perform other types of oil and gas-related inspections or is there specialization of inspection responsibilities?

3. Do supervisors periodically accompany inspectors on field assignments:

4. What training do inspectors receive (initially upon employment and to keep trained on new regulations, industry techniques, etc.)?

5. Is the operator compliance history and selection of wells for inspection coordinated at the field or central office level?

6. Who determines the inspection frequency for each UIC facility?

7. How is communication between field inspectors and the central office staff in charge of UIC permit review handled?

B. Routine/Periodic Inspections

1. How often is each permitted injection well inspected, on average?

2. What aspects of compliance does the inspector evaluate during a routine inspection?

   Is there a compliance checklist?

   How are inspector findings documented, reviewed, and maintained?

   Are there standard inspection forms for routine inspections? Please supply a copy of forms and checklists used.
   Attached? Yes/No (attachment identifier)

   Please describe your program for evaluating compliance with maximum allowable injection pressures.

3. Is the operator given advance notice of inspections? How much?

   Does the agency inspector have statutory right on ingress and egress from leases and UIC well locations to make unannounced inspections. What restrictions, if any, apply?
4. Do inspectors carry their own gauges?

C. Response to Citizen Complaints and Emergency Situations

1. How are citizen or other agency complaints logged and documented?

   Who is responsible for complaint response?

2. How are actions associated with complaint or emergency responses documented?

3. What is the procedure for conducting follow-up to a complaint or emergency response event?

4. Is the operator notified of the complaint? Yes/No

5. What is the typical response time to complaints?

D. Reporting and Follow-Up Procedures

1. Does the agency have a statute or records retention policy regarding the destruction of potentially historical files that would affect the retention of inspection records? Yes/No Describe the records retention policy.

   Does this mandate or policy pertain to hard copy records or records retained in electronic format or both?

2. Where and how are inspections, and violations revealed through inspections tracked to ensure compliance deadlines are met?

   Is this tracking system computerized or primarily manual?

4. Who reviews inspectors' reports?

E. Data Management Systems: Field Access and Use

1. Describe the data management system(s) which are available to field inspectors while conducting routine well inspections as well as providing background support when responding to complaints and emergency situations. The description should delineate how the data management system(s) interfaces with the systems used for other oil and gas regulatory activities.

2. Does your agency use an electronic device to collect data during field inspections? Specify: laptop, tablet, smartphone

3. Is the data management system designed to assist inspector's efforts to track inspection priorities, scheduled inspections, and compliance deadlines?

4. Is GPS data collected during an inspection?

   Are GIS maps available to the inspector for field use?

F. Changes and Modifications to Inspection Program since Primacy

1. Excluding the changes in data management described under Section E above, what statutory, regulatory, policy or budgetary changes have occurred since Primacy that directly affect the UIC field inspection program? Please list or explain.
   Attached? Yes/No (attachment identifier)