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The Class V Underground Injection Control Study

Volume 13

In-Situ Fossil Fuel Recovery Wells

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IN-SITU FOSSIL FUEL RECOVERY WELLS

The U.S. Environmental Protection Agency (USEPA) conducted a study of Class V underground injection wells to develop background information the Agency can use to evaluate the risk that these wells pose to underground sources of drinking water (USDWS) and to determine whether additional federal regulation is warranted. The final report for this study, which is called the Class V Underground Injection Control (UIC) Study, consists of 23 volumes and five supporting appendices. Volume 1 provides an overview of the study methods, the USEPA UIC Program, and general findings. Volumes 2 through 23 present information summaries for each of the 23 categories of wells that were studied (Volume 21 covers two well categories). This volume, which is Volume 13, covers Class V in-situ fossil fuel recovery wells.

1. SUMMARY

In-situ fossil fuel recovery wells are used to facilitate in-situ conversion of a hydrocarbon resource into a gaseous or liquid form that can be extracted through production wells. Specifically, in-situ fossil fuel recovery wells are used to initiate and then to maintain and control combustion through injection of air, oxygen, steam, carbon dioxide, or ignition agents. There are three types of processes that may use in-situ fossil fuel recovery wells: in-situ combustion of tar sand deposits, underground coal gasification (UCG), and in-situ oil shale retorting. In-situ combustion of tar sand deposits has not been employed in the U.S.

Most of the injected materials are gases (e.g., air, oxygen) that are not likely to show exceedances of maximum contaminant levels (MCL) or health advisory levels (HAL). When ignition agents such as ammonium nitrate are injected, exceedances of MCLs or HALs would be expected, but has not been documented.

In-situ fossil fuel recovery wells inject into a hydrocarbon-containing unit, which is often a steeply inclined coal seam or oil shale deposit that is not practical to mine with conventional methods. Although injected gases generally do not introduce contaminants into the subsurface, injection may alter the characteristics of a USDW, if the gases are allowed to contact a USDW, by changing the USDW's temperature or increasing the level of gas saturation.

Contamination of ground water resulting from in-situ fossil fuel recovery operations is well documented, to the extent that most, if not all, in-situ fossil fuel recovery operations initiated in the last 20 years appear to have caused some ground water contamination. The ground water is not contaminated with the injected materials, however. Rather, it is contaminated with combustion byproducts, such as benzene. At some sites, water containing benzene and other combustion byproducts, such as phenols, has migrated via fractures or other means from the reaction zone into nearby ground water.

The in-situ fossil fuel operations conducted in the U.S. have all operated on a trial, rather than full scale basis. The scale of the reaction zone in these cases led to lower temperatures than would be expected in full scale operation. At these lower temperatures, pyrolysis can dominate the process, resulting in greater generation of products of incomplete combustion than would be expected in a full scale operation. In addition, full scale operation would create a larger combustion cavity, resulting in a stronger and more extensive ground water depression zone. Such a depression zone would be expected to cause ground water to flow to, rather than away from, the combustion zone, thus reducing the migration of contaminants outside the combustion zone.

The observed contamination problems are associated with in-situ fossil fuel recovery operations, rather than rare spills or accidents. Overall, in-situ fossil fuel recovery wells are not likely to receive spills or illicit discharges.

According to the state and USEPA Regional survey conducted for this study, there are neither documented nor estimated active in-situ fossil fuel recovery wells in the U.S. The Agency is not aware of plans to construct any new wells.

State UIC regulations in Wyoming and state mining regulations in both Wyoming and Colorado establish permitting and operating requirements for in-situ fossil fuel recovery wells. In both states, mining plans are required that must address siting, construction, operation, monitoring, and closure of production and injection wells. Colorado's mining regulations do not include specific requirements for mechanical integrity testing, plugging and abandonment, or financial assurance. Requirements in Wyoming are both extensive and more specific.

2. INTRODUCTION

The existing UIC regulations at 40 CFR 146.5 define in-situ fossil fuel recovery wells as "injection wells used for in-situ recovery of lignite, coal, tar sands, and oil shale." These wells are used to facilitate conversion of the hydrocarbon resource into a gaseous or liquid form that can be extracted through production wells.[1] When used in conjunction with coal and oil shale formations, these injection wells are used to initiate and then maintain combustion in the coal or oil shale formation through injection of water, air, oxygen, steam, or ignition agents.[2] Injection wells used in the recovery of heavy oils from tar sands are part of "enhanced oil recovery operations" and, thus, are considered Class II injection wells.

Two types of facilities have used Class V in-situ fossil fuel recovery wells: underground coal gasification (UCG) and in-situ oil shale retorting (USEPA, 1987). Development of both types of facilities generally require:

- Formation preparation (e.g., fracturing, dewatering) before or after well drilling, depending on the technique;

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[1] Injection wells used in conjunction with enhanced recovery of oil and gas or production of methane from coal formations are considered Class II injection wells and, thus, are outside the scope of this document.

[2] Wells used for injection as part of in-situ fossil fuel recovery operations may also be used for production at different times during facility operations.

- Well drilling and construction;
- Initiation and maintenance of combustion;
- Controlled movement of the reaction zone throughout the fossil fuel deposit;
- Shutdown and reaction zone cooling; and
- Closure and abandonment.

2.1 Underground Coal Gasification

UCG is a process used to produce gas, primarily hydrogen, carbon monoxide, carbon dioxide, and methane by partially combusting underground coal in the presence of water and a controlled oxygen supply. At the initiation of a UCG operation, injection wells are used to provide ignition agents (e.g., propane or ammonium nitrate--fuel oil (ANFO)), air, steam and/or oxygen, to initiate combustion. Once combustion is established in the coal seam, the injection wells inject air, steam, and/or carbon dioxide to sustain and control the combustion rate.

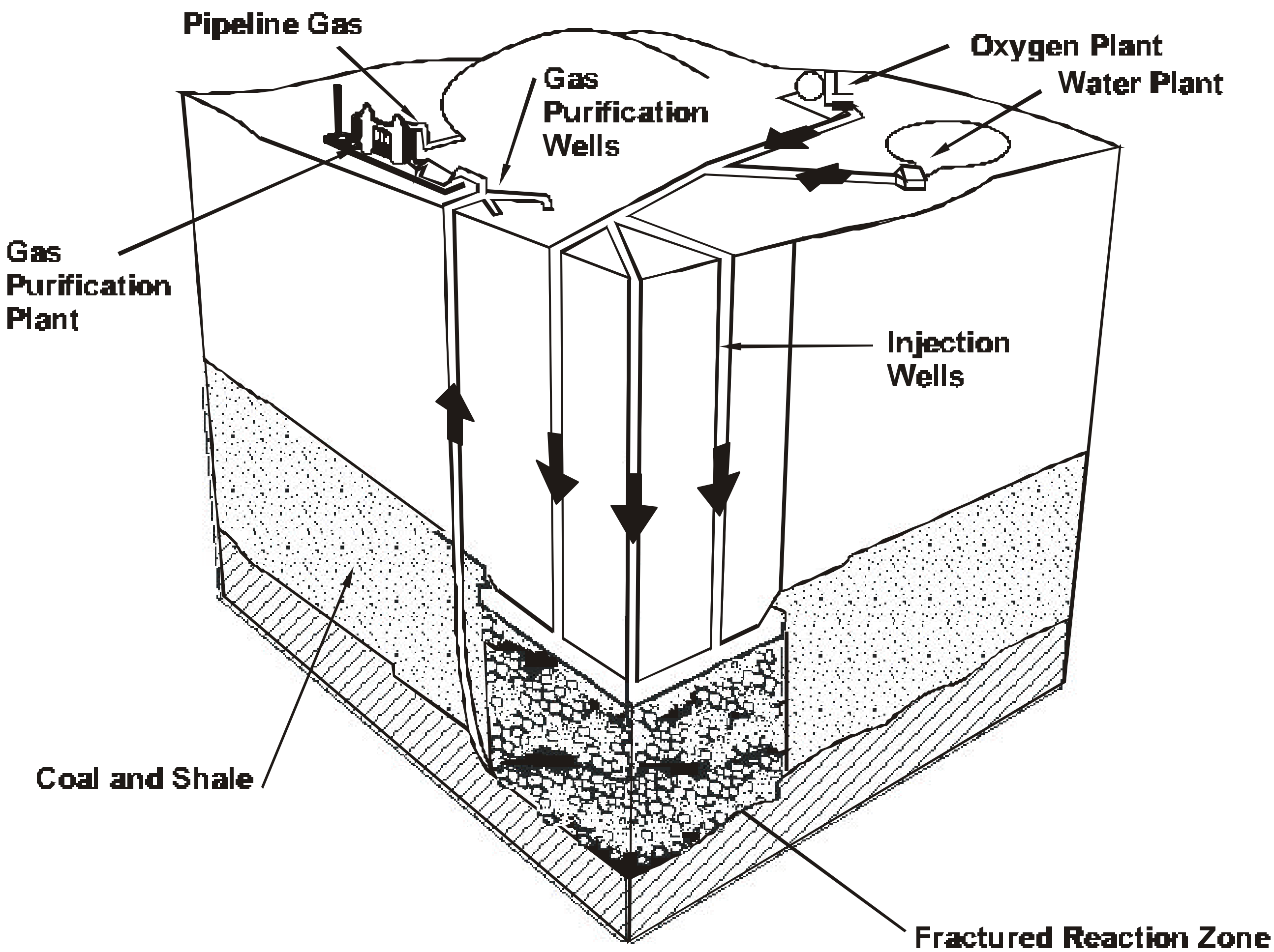
Gas produced by in-situ combustion is recovered through production wells. Between the combustion zone and the production wells, the gas flows through the coal seam and is enriched by products of the reactions and pyrolysis.[3] To facilitate flow of the gas through the coal seam from the combustion zone to the production well(s), a "link" is created by using hydraulic fracturing, directional drilling, electrical linking, reverse combustion, or explosive fracturing. Figure 1 illustrates one potential configuration for injection and production wells. In this example, injection is into the upper portion of the reaction zone and gas production is from a lower portion of the reaction zone. The opposite configuration has also been used, with injection into the lower portion and gas production from the upper portion of the reaction zone. Figure 2 illustrates the "reverse combustion" approach to linking the production and extraction wells. As shown, wells are alternately used for injection and gas production in order to "guide" the combustion process between the wells and thereby create the desired link between the reaction zone and the production well (Krantz, 1983; Hill, 1983).

2.2 In-Situ Oil Shale Retorting

In-situ oil shale retorting (burning) is used to thermally decompose Kerogen and bitumen (tar) in shale to produce gaseous and liquid products that can be refined to produce synthetic

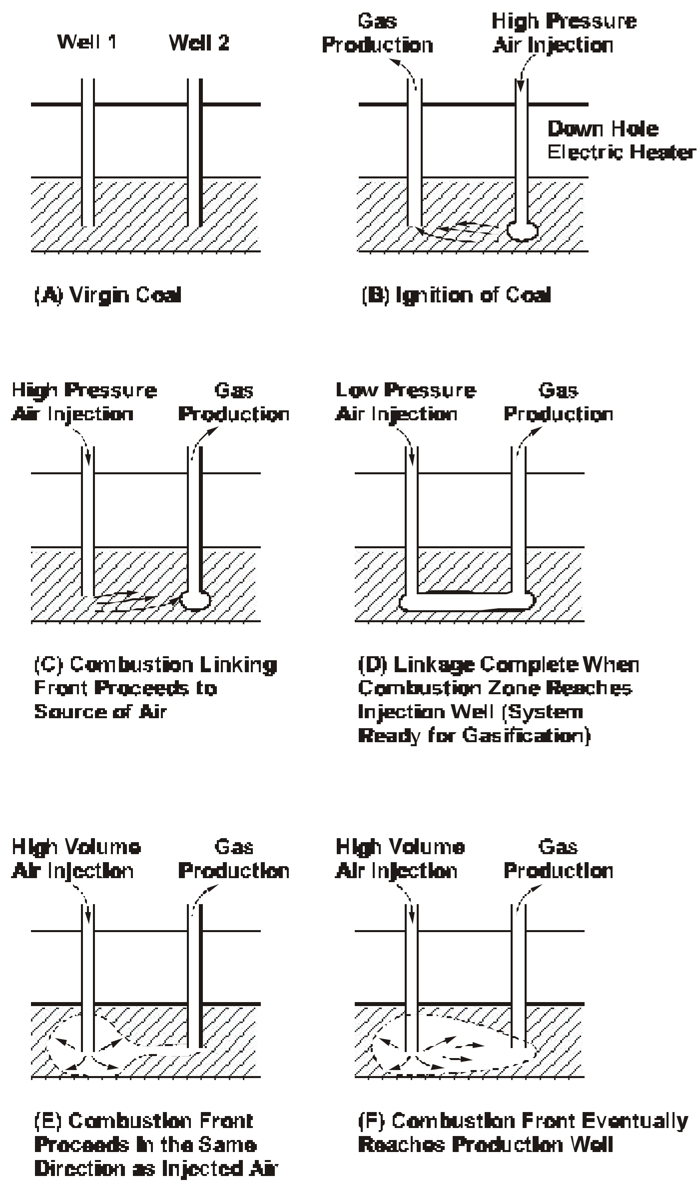
[3] Additional wells may also be drilled into the coal seam for use in dewatering or monitoring the combustion zone.

Figure 1. Example In-Situ Coal Gasification Schematic



Source: Penner, 1984

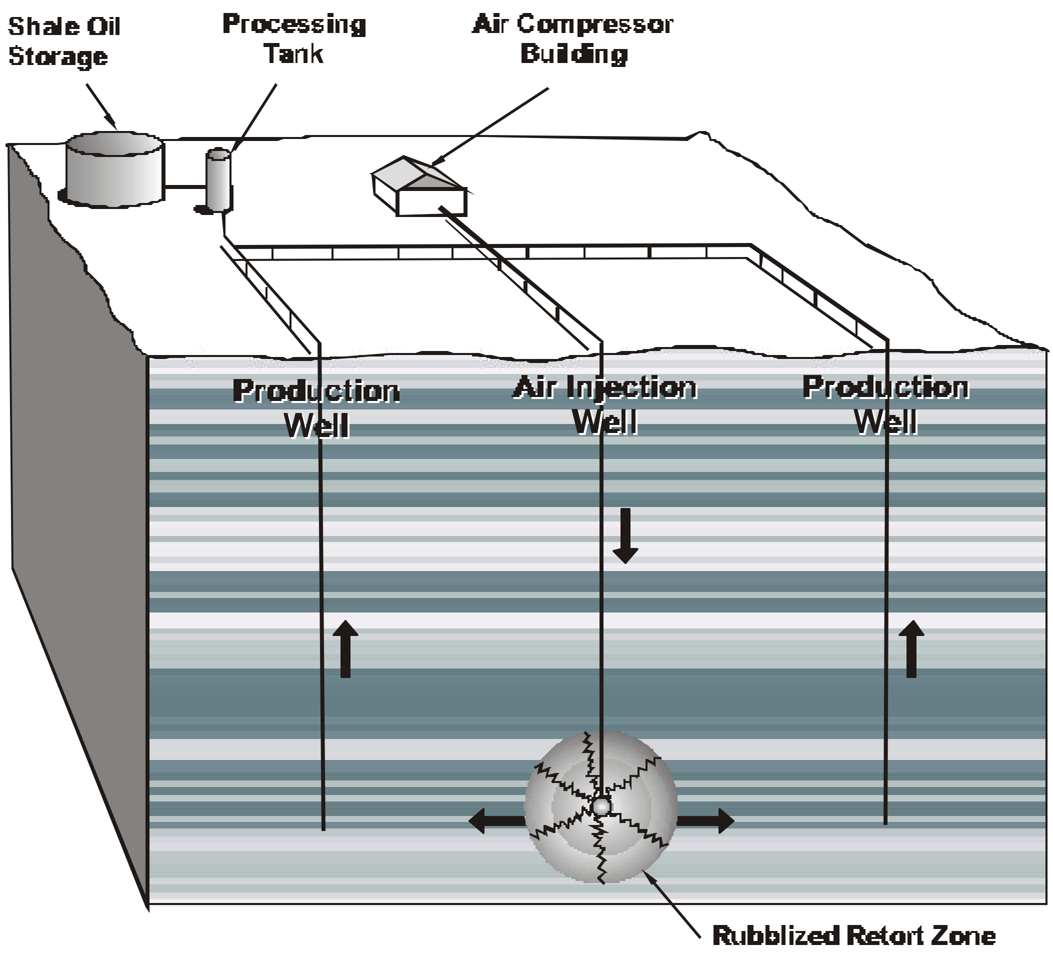
Figure 2. Reverse Combustion Linking



Source: Krantz, 1983

crude oil. Generally, the in-situ oil shale retorting process involves rubblizing a portion of the oil shale zone using explosives or hydraulic fracturing, and then retorting the rubblized shale in place (see Figure 3). In some cases, a portion of the oil shale zone is initially mined prior to rubblizing of the adjacent zone to create a cavity to enhance movement of heated air into the formation and migration of the resulting oil to the production wells. Injection wells are used to initiate the retorting process through injection of heat and air. Once the retorting process is established, the addition of heat from an external source is discontinued and air injection is continued to maintain and control the retort process (Slawson, 1980; Wyoming, 1998a).

Figure 3. Example In-Situ Oil Shale Recovery Process Schematic



Source: Wyoming, 1998a

3. PREVALENCE OF WELLS

For this study, data on the number of Class V in-situ fossil fuel recovery wells were collected through a survey of state and USEPA Regional UIC Programs. The survey methods are summarized in Section 4 of Volume 1 of the Class V Study. Based on the information collected, there are no active in-situ fossil fuel recovery injection wells in the United States. In the past, in-situ fossil fuel recovery wells have operated primarily in Wyoming and Colorado. The Agency is not aware of plans to construct any new wells.

4. INJECTATE CHARACTERISTICS AND INJECTION PRACTICES

4.1 Injectate Characteristics

Injection wells used in in-situ fossil fuel recovery operations may inject air, oxygen, steam, carbon dioxide, or igniting agents to initiate or sustain combustion. Although air, oxygen, steam, and carbon dioxide are not generally considered potential contaminants, these injectates may alter the characteristics of a USDW, if they are allowed to enter the USDW, by changing its temperature or increasing the level of gas saturation. If released to ground water, explosives and ignition agents (used to rubblize or fracture an oil shale or coal formation and then initiate combustion) could cause contamination (USEPA, 1987).

4.2 Well Characteristics

4.2.1 Underground Coal Gasification

UCG wells generally have been less than 600 feet deep, although they have been tested at depths of approximately 2,500 feet (e.g., Thunder Basin in Wyoming). UCG operating conditions require that injection wells be constructed to withstand exposure to extreme thermal and mechanical stresses associated with high pressures, extremely high temperatures (up to 1,500EC for several hours), sulfidation and oxidation, and potential subsidence of the cavity roof.[4] As a result, horizontal wells or directionally drilled wells may be used with the intention of avoiding the extreme temperatures of the combustion zone and the strata deformation caused by cavity collapse and subsidence (Stephens, 1984). The wells are designed to withstand the corrosive conditions created by injection of steam and oxygen or air, and temperatures of 200 to 400EC (Blinderman, 1999). Wells are usually cased with carbon or high strength stainless steel. Cementing of these wells above the reaction zone facilitates controlled introduction of air into the reaction zone and prevents loss of gases to the surface or into other strata such as USDWS through the well bore (Bell, 1983).

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[4] For small-scale tests, the cavities generally collapse to a depth of one-half to one coal-seam thickness above the coal seam, but some tests have caused collapse up to five coal-seam thicknesses and the collapse at Hoe Creek 3 (Wyoming) was to the surface (Stephens, 1984).

4.2.2 In-Situ Oil Shale Retorting

Typically, injection wells used in in-situ oil shale retort applications have ranged from 100 to 1,000 feet in depth, although the wells may be technically feasible at depths of up to 3,000 feet. These facilities can inject into, above, or below a USDW. The injection well casing is cemented to seal the top of the combustion zone, which is required to achieve a consistent shale burn rate. Cementing also prevents water from entering the well bore and loss of gas or fluids that are produced by retorting. As seen with the wells associated with UCG, injection wells involved in the oil shale retorting process are exposed to extremely high temperatures as combustion proceeds within the injection cavity. Therefore, injection wells used to facilitate the retorting of oil shale are cased with carbon or a higher strength stainless steel casing (USEPA, 1987).

4.3 Operational Practices

Injection of air, steam, carbon dioxide, and other fluids (gases) into coal seams and oil shale deposits is an integral and essential part of in-situ fossil fuel recovery operations. In particular, injection rates and the composition of the injection stream affect both the combustion rate and the direction in which combustion proceeds in the coal seam or oil shale deposit. Accordingly, injection operations can be expected to receive on-going oversight as part of operations to monitor and control the in-situ combustion operations.

Available information does not indicate what type of maintenance and mechanical integrity testing (MIT) was performed on in-situ fossil fuel recovery wells in the U.S. while they were operational, perhaps because in-situ burn projects have not lasted more than a few months. At the Carbon County, Wyoming UCG site, which is one of the most recent UCG projects, MIT was required before injection began and subsequently at 5 year intervals. It is important to note, however, that at commercial scale operations in the former USSR, injection wells are expected to have a life of two to four years. At these facilities, MIT is required before injection and in the event that material balance indicates that injectate is being lost in-situ (Blinderman, 1999).

5. POTENTIAL AND DOCUMENTED DAMAGES TO USDWS

5.1 Injectate Constituent Properties

The primary constituent properties of concern when assessing the potential for Class V in-situ fossil fuel recovery wells to adversely affect USDWS are toxicity, persistence, and mobility. The toxicity of a constituent is the potential of that contaminant to cause adverse health effects if consumed by humans. Appendix D to the Class V Study provides information on the health effects associated with contaminants found above drinking water standards or health advisory limits in the injectate of in-situ fossil fuel recovery wells and other Class V wells.

Persistence is the ability of a chemical to remain unchanged in composition, chemical state, and physical state over time. Appendix E to the Class V Study presents published half-lives of common constituents in fluids released in in-situ fossil fuel recovery wells and other Class V wells. All of the values reported in Appendix E are for ground water. Caution is advised in interpreting these values because ambient conditions have a significant impact on the persistence of both inorganic and organic compounds. Appendix E also provides a discussion of mobility of certain constituents found in the injectate of in-situ fossil fuel recovery wells and other Class V wells.

Constituents that were found to exceed health-based standards in ground water at one or more in-situ fossil fuel recovery sites include ammonia, nitrate, and benzene.[5,6] Benzene is moderately persistent in ground water. Estimates of the half-life in ground water range from 240 to 17,000 hours. Based on this information alone, benzene would receive a persistence rating of high based on the criteria used in Appendix E. Nitrate is persistent in aerobic environments but may break down rapidly to nitrogen gas in anaerobic environments. Ammonia is persistent in ground water if dissolved oxygen levels are low (e.g., < 1 ppm) but will generally convert to nitrate when dissolved oxygen levels are higher.

The point of injection for in-situ fossil fuel recovery wells is typically within a fractured or rubblized area of a coal or shale seam that is often water bearing. In addition, the natural fractures, joints, and cleats of coal seams also provide pathways for water and gas migration. These conditions combine along with the water solubility of the constituents to provide an environment that enables relatively high contaminant mobility. This is indicated in part by the results of the pilot scale operations that have been conducted in the U. S. In a full scale application of the UCG process, which has not occurred in the U. S., a larger combustion cavity would be created, resulting in a stronger and more extensive ground water depression zone. Such a zone of depression would be expected to cause ground water to flow to, rather than away from, the combustion zone, thus reducing the mobility of contaminants in ground water outside of the combustion zone (Blinderman, 1999).

5.2 Impacts on USDWS

As noted in Section 3.1 above, most of the materials injected into in-situ fossil fuel recovery wells have little potential for degrading the quality of USDWS. One exception is an explosive/ignition agent used at the initiation of the combustion process. Such materials could potentially degrade ground water quality if they were released to ground water (if any is present) as a result of a well casing leak. In addition, they could potentially degrade ground water quality in the event of incomplete combustion or failure to ignite at a site where the combustion zone is also an aquifer. Consistent with the discussion above concerning contaminant mobility, such problems are expected to be less likely during full scale operations than in the pilot tests conducted to date.

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[5] These constituents are thought to be products of the combustion process and not present to any significant extent in the injected fluids, with the possible exception that ammonia and nitrate if they are injected to aid in initiating combustion.

[6] Other compounds such as phenols and pyridine may be present as a result of combustion, but the concentration of these compounds, if present, is not clear based on the available data.

In addition to producing gas or oil, in-situ combustion of fossil fuels also produces combustion byproducts and residuals, including ash and hydrocarbons that remain in the formation. Combustion ash typically contains trace metals, such as arsenic, lead, mercury, selenium, and chromium (USEPA, 1990). Hydrocarbons may include phenols, tars, polynuclear aromatic and heterocyclic compounds (USEPA, 1987).

Contamination of ground water has been attributed to several in-situ fossil fuel recovery operations, including those at Hoe Creek and Rock Springs, Wyoming and Rio Blanco, Colorado. As discussed in more detail below, it appears that the primary contaminants (e.g., phenols, benzene) are products of incomplete combustion rather than components of the injected gases and fluids.

Although data on the composition of injected water are not available, the site-specific factors that are the basis for this generalized assessment are discussed below. It should be noted that in all of the examples discussed, UCG was conducted on a trial, rather than full scale basis. The scale of the reaction zone in these cases led to lower temperatures than would be expected in full scale operation. This caused pyrolysis to dominate, resulting in greater generation of products of incomplete combustion than would be expected in a full scale operation.

5.2.1 Hoe Creek

Three UCG pilot-scale test burns were performed between 1976 and 1979 at the Hoe Creek site near Gillette, Wyoming. Ground water samples collected from the two gasified coal seam aquifers (Felix I and II) and an overlying channel sand aquifer following completion of the tests indicated that: (1) collapse of the roof of the cavity created by gasification had interconnected the three aquifers; (2) ground water was recharging the reaction zone; and (3) a broad range of organic combustion products (especially phenols) had been introduced into the ground water system (Wang, 1983; Nordin, 1987). Samples from more than 12 wells in the vicinity of the UCG site showed a greatly increased concentration of organic materials, particularly phenols, just outside the burn boundary and a variety of inorganic species released from within the residual ash bed (Campbell, 1979). In 1993, the U.S. Department of Energy (DOE) prepared a Preliminary Assessment and concluded that ground water contamination at the site posed potential future risk to humans and livestock ingesting water from nearby wells, as well as risk to wetlands habitat down gradient of the site (Dames & Moore, 1996).

Ground water remediation, including a "pump and treat" system with activated carbon for removal of organic compounds, has been implemented. As a result of these treatment operations, as well as natural attenuation, ground water quality has improved. However, some organic contaminants, especially benzene and phenols, remain. The Felix I coal seam contained the highest concentration of both benzene and total phenols, with benzene concentrations ranging up to 1 ppm. Benzene and phenols were also detected in the channel sand aquifer and the Felix 2 coal seam (Dames & Moore, 1996).

5.2.2 Rio Blanco

The Rio Blanco in-situ fossil fuel recovery project was an oil shale retorting operation located in Rio Blanco County, Colorado that conducted two retort trials in 1980 and 1981. As shown in Figure 4, the target oil shale formation coincides with an "upper aquifer." The upper aquifer is made up of two permeable zones with highly permeable sections (the A-Groove and B-Groove) immediately above and slightly below the fractured Mahogany Zone (Abel, 1994).

As shown in Figure 4, dewatering wells and shafts were installed to prevent water from the Mahogany zone and the B-Groove from entering the retort zone. Collapse of the retort zone ceiling, which provided connection to the A-Groove, and failure of a dewatering pump, however, allowed flooding of the lower 300 feet of the retort zone. As a result, ground water in and down gradient from the retort zone became contaminated with benzene (and other soluble combustion byproducts), based on sampling at depths ranging from 400 to 840 feet below ground surface (Rio Blanco Oil Shale Company, 1995 and 1997).

Ground water monitoring conducted since the mid-1980s documented the concentration of both organic and inorganic constituents. The data indicate that benzene concentrations in the ground water reached a maximum of 0.29 mg/l in 1988. By 1997, the benzene levels declined to less than 0.001 mg/l due to naturally occurring bioremediation, decreased rate of release from the source rock, and attenuation. Data also indicate that the concentrations of inorganic water quality parameters, which were initially elevated following the flooding of the reaction zone, have essentially returned to pre-retorting values. Minor amounts of organic substances still exist in the lower part of the retort rubble, but are not highly mobile due to the impermeable nature of the surrounding oil shale formation at that depth (Abel 1994; Rio Blanco Oil Shale Company, 1995 and 1997).

5.2.3 Carbon County

Field tests of UCG in a steeply dipping coal seam in the Indian Springs Coal Resource area near Rawlins, Wyoming (in Carbon County) were conducted in April and August, 1995.[7] Monitoring before and after the test burns showed that the concentration of some organic constituents increased following the test burns. In particular, the concentration of benzene in water samples collected from the injection wells following the test burns ranged from <0.005 mg/l to approximately 1.6 mg/l, with most values in the range of 0.1 to 0.3 mg/l. In most wells, concentrations have decreased over time, but generally remain above the Primary Drinking Water Standard of 0.005 mg/l (Carbon County UCG, 1998).

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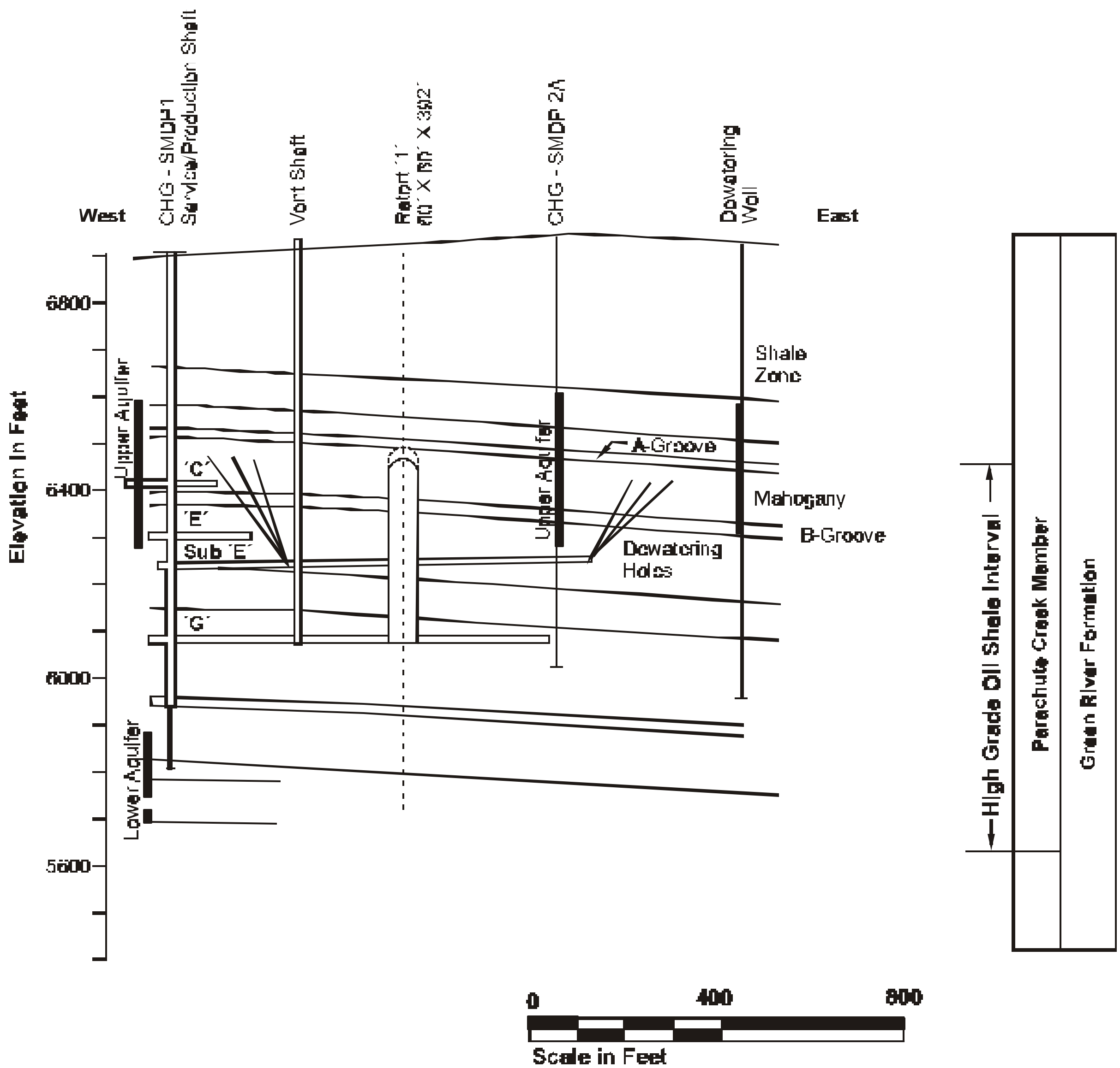
[7] Earlier testing was also conducted in 1979 and 1981. Ground water monitoring prior to, during, and after the tests indicated that changes in water quality were slight, but included increases in total organics, phenols, and some dissolved salts (Carbon County UCG, Inc., 1994).

Figure 4. Hydrogeologic Cross Section at Rio Blanco



Source: Abel, 1994

Monitoring of ground water outside the reaction zone was also conducted in the target coal horizon (designated "G") and in overlying sandstone (designated "U") and underlying sandstone (designated "L"). Increases in benzene concentrations following the test burns were observed in all three horizons. Increases to levels above the MCL (0.005 mg/l) occurred most frequently in wells installed in the G horizon. Benzene concentrations as high as 20 mg/l were observed in the U horizon. The highest concentration observed in the L horizon was 0.028 mg/l. Both of these maximum concentration values were observed in the monitoring well cluster installed closest to the reaction zone and shortly after the test burn was conducted 1995. By 1998, benzene concentrations in this L horizon well had declined to about 0.005 mg/l, while concentrations in the U horizon well had declined by approximately a factor of 10 (Carbon County UCG, 1998).

Benzene was also observed at monitoring wells 600 feet from the reaction zone. Concentrations in the U horizon were 0.0068 to 0.015 mg/l. In the G horizon, monitoring well concentrations were generally between 0.005 and 0.01 mg/l, but were reported to be as high as 49 mg/l in one well (Carbon County UCG, 1998). One of these wells is located more than 600 feet north of the reaction zone while another is approximately the same distance to the south.

6. ALTERNATIVE AND BEST MANAGEMENT PRACTICES

A number of best management practices (BMPs) can be implemented to provide increased protection of USDWS from in-situ fossil fuel recovery operations. The BMPs listed below are most effective when selected and implemented in combinations that are based on site-specific factors, which are highly variable. Individually, each practice addresses specific challenges and problems that may occur.

The following discussion notes BMPs for both injection wells and in-situ fossil fuel recovery operations that are closely related to the protection of ground water quality. The discussion is neither exhaustive nor represents an USEPA preference for the stated BMPs. Each state, USEPA Region, and federal agency may require certain BMPs to be installed and maintained based on that organization's priorities and site-specific considerations.

6.1 Well Design and Construction

Well integrity is important both for protecting USDWS (where present) and controlling the combustion process. When siting the injection well, it is important to avoid locating the well in areas of rock deformation and subsidence that could affect its integrity. In some cases, appropriate siting may need to be achieved through use of directional drilling. In addition, well construction materials (pipe and cement) need to be capable of withstanding elevated temperatures and corrosion caused by the injected fluids. To ensure that construction achieves the desired well integrity, initial mechanical integrity testing is needed.

6.2 Well Operation

The pressure at which air, steam, or other gases/fluids are injected is important both for controlling the in-situ combustion process and for preventing loss of produced gases and migration of contaminants from the reaction zone. As indicated by the experience with the second test burn at the Hoe Creek site, too high an injection pressure contributed to ground water contamination. Thus, the appropriate limits on injection pressure need to be determined in advance and injection pressure needs to be monitored and controlled so that it is maintained at appropriate levels.

Maintaining an appropriate injection flow rate is also important to the overall operation of the UCG process. If a sufficiently high gas flow rate is maintained in both the injection and production wells, then the gas flow will serve to air-lift ground water and contaminants to the surface. In addition, an appropriate flow rate is important to maintaining the desired combustion temperature and ensuring combustion of contaminants (Blinderman, 1999).

6.3 Burn Front Monitoring and Control

As noted in Section 4, the cavities created by in-situ combustion may result in formation collapses that risk compromising the integrity of injection and production wells and may otherwise allow ground water to migrate through the reaction zone. Thus, monitoring and controlling the burn front is important to preventing ground water contamination.[8] One technique that has been used is the high frequency electromagnetic burn front location technique (HFEM). HFEM provides a way to measure cavity size and position around the injection well that avoids the use of additional nearby monitoring wells. Knowledge of cavity size and position reduces the associated risk of creating an unintended path for the burn front and inducing fractures in the coal seam (Wyoming 1998b).

6.4 Closure and Abandonment

When coal seams used for in-situ fossil fuel recovery have hydraulic communication with a USDW, combustion by-products, especially water-soluble contaminants such as benzene, that remain in the reaction zone after combustion must be removed to avoid ground water contamination. At the test sites operated in the past, this has typically been accomplished by repeated flushing (e.g., controlled flooding and pumping) of the reaction zone. In addition, plugging the entire length of the well and abandoning injection production, and monitoring wells is important for protecting ground water from contamination. Plugging may be achieved with cement and/or other materials such as bentonite or drilling mud to prevent contaminant migration in the well bore. Depending on the type of bottom hole completion and the position of the well in relation to the reaction zone cavity, this may require setting a packer at the bottom of the casing and filling the well.

[8] Both control of the burn zone geometry and complete combustion, which minimizes the presence of ground water contaminants in the reaction zone, are facilitated by uniform rubblization or other means of providing a reliable and uniform link between the injection and production wells.

7. CURRENT REGULATORY REQUIREMENTS

Several federal, state, and local programs exist that would either directly manage or regulate Class V in-situ fossil fuel recovery wells. On the federal level, management and regulation of these wells fall primarily under the UIC program authorized by the Safe Drinking Water Act (SDWA). Some states and localities have used these authorities, as well as their own authorities, to extend the controls in their areas to address concerns associated with in-situ fossil fuel recovery wells.

7.1 Federal Programs

Class V wells are regulated under the authority of Part C of SDWA. Congress enacted the SDWA to ensure protection of the quality of drinking water in the United States, and Part C specifically mandates the regulation of underground injection of fluids through wells. USEPA has promulgated a series of UIC regulations under this authority. USEPA directly implements these regulations for Class V wells in 19 states or territories (Alaska, American Samoa, Arizona, California, Colorado, Hawaii, Indiana, Iowa, Kentucky, Michigan, Minnesota, Montana, New York, Pennsylvania, South Dakota, Tennessee, Virginia, Virgin Islands, and Washington, DC). USEPA also directly implements all Class V UIC programs on Tribal lands. In all other states, which are called Primacy States, state agencies implement the Class V UIC program, with primary enforcement responsibility.

In-situ fossil fuel recovery wells currently are not subject to any specific regulations tailored just for them, but rather are subject to the UIC regulations that exist for all Class V wells. Under 40 CFR 144.12(a), owners or operators of all injection wells, including in-situ fossil fuel recovery wells, are prohibited from engaging in any injection activity that allows the movement of fluids containing any contaminant into USDWS, "if the presence of that contaminant may cause a violation of any primary drinking water regulation . . . or may otherwise adversely affect the health of persons."

Owners or operators of Class V wells are required to submit basic inventory information under 40 CFR 144.26. When the owner or operator submits inventory information and is operating the well such that a USDW is not endangered, the operation of the Class V well is authorized by rule. Moreover, under section 144.27, USEPA may require owners or operators of any Class V well, in USEPA-administered programs, to submit additional information deemed necessary to protect USDWS. Owners or operators who fail to submit the information required under sections 144.26 and 144.27 are prohibited from using their wells.

Sections 144.12(c) and (d) prescribe mandatory and discretionary actions to be taken by the UIC Program Director if a Class V well is not in compliance with section 144.12(a). Specifically, the Director must choose between requiring the injector to apply for an individual permit, ordering such action as closure of the well to prevent endangerment, or taking an enforcement action. Because in-situ fossil fuel recovery wells (like other kinds of Class V wells) are authorized by rule, they do not have to obtain a permit unless required to do so by the UIC Program Director under 40 CFR 144.25. Authorization by rule terminates upon the effective date of a permit issued or upon proper closure of the well.

Separate from the UIC program, the SDWA Amendments of 1996 establish a requirement for source water assessments. USEPA published guidance describing how the states should carry out a source water assessment program within the state's boundaries. The final guidance, entitled *Source Water Assessment and Programs Guidance* (USEPA 816-R-97-009), was released in August 1997.

State staff must conduct source water assessments that are comprised of three steps. First, state staff must delineate the boundaries of the assessment areas in the state from which one or more public drinking water systems receive supplies of drinking water. In delineating these areas, state staff must use "all reasonably available hydrogeologic information on the sources of the supply of drinking water in the state and the water flow, recharge, and discharge and any other reliable information as the state deems necessary to adequately determine such areas." Second, the state staff must identify contaminants of concern, and for those contaminants, they must inventory significant potential sources of contamination in delineated source water protection areas. Class V wells, including in-situ fossil fuel recovery wells, should be considered as part of this source inventory, if present in a given area. Third, the state staff must "determine the susceptibility of the public water systems in the delineated area to such contaminants." State staff should complete all of these steps by May 2003 according to the final guidance.[9]

7.2 State and Local Programs

As discussed in Section 3 above, no states have active in-situ fossil fuel recovery wells.[10] Most wells that have operated in the past appear to have occurred in Wyoming and Colorado. Attachment A of this volume describes how these two states address in-situ fossil fuel recovery wells (although no such wells currently exist).

In brief, Wyoming is a UIC Primacy State for Class V wells and requires individual permits for in-situ fossil fuel recovery wells issued by the Water Quality Division of the Department of Environmental Quality (DEQ). The state requires the submission of detailed information, and incorporates specific operating requirements as permit conditions. In-situ fossil fuel recovery wells also are required to satisfy the state's rules pertaining to coal mining (or, when appropriate non-coal mining) administered by the Land Quality Division of DEQ.. In Colorado, the wells are authorized by rule under the Class V UIC program, which is implemented directly by USEPA Region 8. In addition, the State of Colorado requires permits for in-situ fossil fuel recovery wells under the state's mining regulations. These permitting requirements include mandatory submission of detailed information about the operation; site hydrology; specifications of the proposed drill holes and casings; and preparation of an operations plan, including a separate monitoring plan and a remediation plan. The rules for in-situ operations also include specific operating requirements.

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[9] May 2003 is the deadline including an 18-month extension.

[10] At some sites, wells previously used for injection as part of in-situ fossil fuel recovery operations may now be used as part of ground water remediation activities.

ATTACHMENT A
STATE AND LOCAL PROGRAM DESCRIPTIONS

This attachment focuses on the two states that most recently had in-situ fossil fuel recovery wells, although neither has active injection wells of this type.

Colorado

USEPA Region 8 directly implements the Class V UIC program in Colorado. The state has not enacted requirements directly addressing in-situ fossil fuel recovery wells as part of an injection well program. However, the state has enacted extensive requirements pertaining to mining under the authority of the Colorado Surface Coal Mining Reclamation Act (SCMRA) Title 34, Article 33 of the Colorado Revised Statutes. Regulations of the Colorado Mined Land Reclamation Board for coal mining enacted by the Colorado Division of Minerals and Geology (DMG) address in-situ processing. The regulations define "in-situ processes" as "activities conducted on the surface or underground in connection with in place distillation, retorting, leaching or other chemical or physical processing of coal. The term includes, but is not limited to, in-situ gasification, in-situ leaching, slurry mining, solution mining, borehole mining and fluid recovery mining" (Rule 1.04 (68)). Underground mining activities include underground operations such as construction, operation, and reclamation of shafts, adits (horizontal mine passages), underground support facilities, and in-situ processing (Rule 1.04 (144)). The Colorado Mined Lands Reclamation Act (CMLRA) also provides authority for rules pertaining to surface disposal of wastes from in-situ operations (34-32-103 (8) CMLRA).

Permitting

The coal mining regulations establish permitting requirements for special categories of mining, including in-situ processing activities (Rule 2.06.11). An application for a permit must satisfy all the requirements in Rule 2 applicable to underground mining activities. They include a detailed description of the site, including hydrology and geology, an operation plan, and a reclamation plan (Rule 2.04 and 2.05). In addition, an application for an in-situ processing operation also must provide the following:

- Delineation of proposed holes and wells and production zone for approval by the DMG.
- Specifications of drill holes and casings proposed to be used.
- A plan for treatment, confinement, or disposal of all acid forming, toxic forming, or radioactive gases, solids, or liquids constituting a fire, health, safety, or environmental hazard caused by the mining and recovery process.
- Plans for monitoring surface and ground water and air quality, as required by DMG (Rule 2.06.11(2)).

No permit may be issued unless the DMG finds that the performance standards of Rule 4, and particularly 4.29 pertaining to in-situ operations, are met.

Operating Requirements

The performance standards applicable to in-situ processing specify that the operation must comply with the subsidence control standards of Rule 4 (Rule 4.20) and with the special requirements for in-situ operations in Rule 4.29. It requires operators to:

- Plan and conduct activities to minimize disturbance to the prevailing hydrologic balance by (a) avoiding discharge of fluids into holes or wells, other than as approved by the DMG; (b) injecting process recovery fluids only into geologic zones or intervals approved as production zones by DMG; (c) avoiding annular injection between the wall of the drill hole and the casing; and (d) preventing discharge of process fluid into surface waters.
- Adhere to the plans submitted as part of the permit application under Rule 2.06.11.
- Prevent flow of the process recovery fluid (a) horizontally beyond the affected area identified in the permit; and (b) vertically into overlying or underlying aquifers.
- Restore the quality of affected ground water in the permit and adjacent area, including ground water above and below the production zone, to the approximate pre-mining levels or better, to ensure that the potential for use of the ground water is not diminished (Rule 4.29.2).

Monitoring is required of the quality and quantity of surface and ground water and subsurface flow and storage characteristics, in a manner approved by DMG in accordance with Rule 4.05.13, to measure changes in the quantity and quality of water in surface and ground water systems in the permit and adjacent areas (Rule 4.29.3).

Mechanical Integrity Testing

No requirements.

Financial Assurance

Rule 3 provides performance bond requirements for completion of the reclamation plan, but those requirements specify only surface coal mining and reclamation activities and thus do not apply to in-situ fossil fuel recovery wells (Rule 3.02).

Plugging and Abandonment

Rule 4.30 provides general requirements for cessation of operations, but contains no specific requirements pertaining to plugging and abandonment.

Wyoming

Wyoming is a UIC Primacy State for Class V wells and the Wyoming Department of Environmental Quality (DEQ) Water Quality Division (WQD) has promulgated regulations pertaining to its Class V UIC program in Chapter 16, Water Quality Rules and Regulations (WQRR). In-situ fossil fuel recovery wells are not named as a specifically defined Class V well type under Chapter 16, and therefore fall into category 5F2, which includes all other Class V facilities that inject fluids into or above a USDW that do not fall into Class I, II, III, or IV injection facilities. All type 5F2 Class V wells are required to obtain an individual permit (16 WQRR Appendix B). In addition, in-situ fossil fuel recovery wells are regulated by the Land Quality Division (LQD) of the Wyoming DEQ under the Surface Mining Reclamation and Control Act (SMRCA) and are required to satisfy the state's rules pertaining to coal mining (or, when appropriate, the equivalent rules pertaining to non-coal mining).

UIC Requirements

<u>Permitting</u>. In-situ fossil fuel recovery facilities (category 5F2) are covered by the Individual Permit provisions of the state's Class V rules (Chapter 16 Section 6 WQRR). A separate permit to construct under Chapter 3 WQRR (the state's regulations for permits to construct, install, or modify public water supplies, wastewater facilities, disposal systems, biosolids management facilities, treated wastewater reuse systems, and other facilities capable of causing or contributing to pollution) is not required, but requirements of the Chapter 3 permit are included in the UIC permit (Chapter 16, Section 5 (v) WQRR). A UIC permit must be obtained prior to the construction, installation, modification, or operation of a facility. The application must include the following (Chapter 16 Section 6 WQRR):

- Description of the business and the activities to be conducted;
- Name, address, telephone number, and ownership status of the operator;
- Name, address, telephone number, and location of the facility;
- Calculation of the maximum area affected by the injected material (the area of review) and legal description by township, range, and section to the nearest 10 acres of the area of review;
- Facility information, including description of the substances to be discharged by type; source; chemical, physical, radiological, and toxic characteristics; and construction and engineering details satisfying Chapter 16 Section 10 and Chapter 11 WQRR (the state's regulations on design and construction standards for sewerage systems, treatment works, disposal systems, or other facilities capable of causing or contributing to pollution);
- Information, including name, description, depth, geologic structure, faulting, fracturing, lithology, hydrology, and fluid pressure of the receiving formation and any relevant confining zones;
- Water quality information, including background water quality data sufficient to enable the WQD to classify the receiver and any secondarily affected aquifers under Chapter 8 WQRR;
- Topographic and other pertinent maps, extending at least 1 mile beyond the property boundaries of the facility but never less than the area of review, depicting the facility and each intake and discharge structure, each well, drywell, or subsurface fluid distribution system where fluids from the facility are injected underground; other wells, springs, and surface water bodies and drinking

water wells within the area of review; bedrock and surface geology, geologic structure, and hydrogeology in the area;

- Other relevant federal or state permits, including construction permits, and a statement whether the facility is within a water quality management area, wellhead protection area, or source water protection area; and
- Plans for monitoring the volume and chemistry of the discharge and water quality of selected water wells within the area of review.

Siting and Construction. Class V facilities may not be located within 500 feet of any active public water supply well, regardless of whether or not the well is completed in the same aquifer. This minimum distance may increase or the existence of a Class V well may be prohibited within a wellhead protection area, source water protection area, or water quality management area (Chapter 16 Section 10(n) WQRR).

The facility must submit notice of completion of construction to the DEQ, and allow for inspection upon completion of construction prior to commencing any injection activity (Chapter 16 Section 5 (c)(i)(U) WQRR).

Operating Requirements. The permit conditions specified for individual permits include a requirement that the permittee properly operate and maintain all facilities and systems, furnish information to the DEQ upon request, allow inspections, establish a monitoring program pursuant to Chapter 16 Section 11 WQRR and report monitoring results, give prior notice of physical alterations or additions, and orally report confirmed noncompliance resulting in the migration of injected fluid into any zone outside of the permitted receiver within 24 hours and follow-up with a written report within 5 days. Detailed informational requirements are also included in the individual permit, including requirements established on a case-by-case basis for monitoring, schedules of compliance, and additional conditions necessary to prevent the migration of fluids into USDWS (Chapter 16 Section 5 (c)(ii) WQRR). Monitoring program requirements are also specified in any circumstances where ground waters of the state could be affected by a Class V facility (Chapter 16 Section 11 WQRR).

Mechanical Integrity. Permittees are required to adopt measures to insure the mechanical integrity of any well designed to remain in service for more than 60 days. No specific regulatory requirements on mechanical integrity testing have been enacted; the specific tests to be used depend on the specific well conditions.

Financial Responsibility. No requirements.

Plugging and Abandonment. Wells may be abandoned if it is demonstrated to DEQ that no hazardous waste or radioactive waste has ever been discharged through the facility, all piping allowed for the discharge has either been removed or the ends of the piping have been plugged in such a way that the plug is permanent and will not allow for a discharge, and all accumulated sludges are removed from holding tanks, lift stations, or other waste handling structures prior to abandonment (Chapter 16 Section 12 (a) WQRR).

Mining Requirements

The Wyoming Environmental Quality Act (WEQA), Article 4 "Land Quality," establishes requirements for in-situ mineral mining permits and duties (Sections 35-11-426 to 35-11-430 WEQA). The law specifies that all provisions of the act applicable to surface coal mining operations (defined at 35-11-103(e)(xx) to include in-situ distillation and retorting) shall apply to coal in-situ operations (35-11-426(a) WEQA). Therefore, a mining permit is required from the LQD in addition to the UIC permit required from WQD (35-11-427 WEQA).

Permitting. Requirements for applications for coal in-situ mining permits are established by statute (35-11-428 WEQA), by the coal mining regulations (CMR) (Chapter 3 Section 3 CMR and Chapters 5, 7, and 18 CMR), and by a detailed guideline prepared by the LQD (Guideline No. 6A: "Format and General Content Guideline for Permit Applications, Amendments, and Revisions for Coal Mining Operations," 8/94 (revised), pp. 1-18). In addition, Land Quality guideline No. 4, "In-Situ Mining," has also been issued by the LQD. (The guidelines state that "contents are not to be interpreted by applicants or DEQ staff as mandatory" but are intended to serve as checklists for the assistance of applicants.)

The WEQA provides that no in-situ mining operation may be initiated or conducted unless a valid mining permit has been issued to the operator. Construction and completion of drill holes or wells (for mineral exploration) may be authorized prior to issuance of a mining permit (35-11-427 and 35-11-404(a) WEQA), but the administrative procedures of the WEQA, with respect to aquifers, may not be waived for drilling in conjunction with coal mining or exploration (35-11-404(g) WEQA).

The statutory requirements for a mining permit application include the following:

- Satisfaction of the general permit application requirements pertaining to the mining and reclamation plan in § 35-11-406(b)(i),(iv), (viii) to (xiv) WEQA;
- Surface information, including surface water; and
- Geologic and ground water hydrologic information, including a description of the general geology, including geochemistry and lithology, characterization of the production zone and aquifers that may be affected, including hydrologic and water chemistry data; a mine plan and reclamation plan, a description of mining techniques, a statement of past, present, and proposed post-reclamation use of the land, ground water, and surface water; site facility description, contour map, assessment of impact on water resources on adjacent lands, plans and procedures for environmental surveillance and excursion detection, prevention, and control programs, procedures for land reclamation, procedures for ground water restoration, and estimated costs of reclamation (35-11-428 WEQA). Additional details concerning these requirements are provided in Guideline No. 6A.

The regulatory requirements for permitting coal in-situ processing activities specify that the applicant must demonstrate how it will comply with: (1) the WEQA; (2) Chapter 18 of the coal mining regulations on "In-Situ Mining;" (3) Chapter 5 Section 4 of the coal mining regulations on performance standards for coal in-situ processing; and (4) Chapter 7 on underground coal mining permit application requirements and environmental protection performance standards (Chapter 3 Section 3 WCR).

Chapter 18 provides that both the LQD and the WQD will review the in-situ mining application. The permit application requirements specify in detail a broad range of information that must be supplied, including the following information pertaining to ground water and drinking water:

- A description of the geology, including maps, cross-sections and supporting geologists, drillers, and geophysical logs which identify: formations and aquifers, geologic features that could influence aquifer properties, and the areal and stratigraphic position of the production zone in relation to other geologic features;[11]
- Tabulated water quality analyses for samples collected from all ground waters that may be affected by the proposed operation. Sampling to characterize the pre-mining ground water quality and its variability must be conducted in accordance with DEQ guidelines;
- A ground water potentiometric surface contour map for each aquifer that may be affected by the mining process;
- Name, description, and map of all surface waters within the permit area and on adjacent lands, and a list and mapping of all adjudicated and permitted water surface and ground water rights within and adjacent to the permit area;
- Aquifer characteristics for the water saturated portions of the receiving strata and aquifers that may be affected by the mining process, including detailed specifications concerning the data that must be submitted, such as aquifer thickness, velocity and direction of ground water movement, storage coefficients or specific yields, transmissivity or hydraulic conductivity and the directions of preferred flow under hydraulic stress in the saturated zones of the receiving strata, extent of hydraulic connection between the receiving strata and overlying and underlying aquifers, and the hydraulic characteristics of any influencing boundaries in or near the proposed well field areas;
- Geochemical description of the receiving strata and any aquifers that may be affected by the injection of recovery fluid;
- Locations of water wells within the permit area, including well completion data, producing intervals, and variations in water level. Mapping of all wells within and adjacent to the permit area; and
- Tabulation of all abandoned wells and drill holes.

Chapter 18 also requires a mining plan, including all information required by the WEQA, and also information on injection pressures, injection rate, and type of recovery fluid to be used; description of chemical reactions that may occur during mining as a result of recovery fluid injection; procedures to verify that the injection and recovery wells are in communication with monitoring wells in the receiving strata; procedures to ensure that the installation of recovery, injection, and monitor wells will not result in hydraulic communication between the production zone and overlying stratigraphic horizons; and a schedule and procedures for checking mechanical integrity.

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[11] Wyoming defines groundwater as "subsurface water that fills available openings in rock or soil materials such that they may be considered water saturated under hydrostatic pressure" (VIII WQRR 2(f); IX WQRR 2(l); XVI WQRR 2(m)). Aquifer is defined as "a zone, stratus or group of strata that can store and transmit water in sufficient quantities for a specific use" (VIII WQRR 2(a); IX WQRR 2(a); XVI WQRR 2(a)).

Furthermore, Chapter 18 requires a reclamation plan, including all information required by the WEQA, and also information necessary to demonstrate:

> ". . . that the operation will return all affected ground water, including affected ground water within the production zone, receiving strata, and any other areas, to a condition such that its quality of use is equal to or better than, and consistent with, the uses for which the water was suitable prior to the operation by employing the best practicable technology."

Operating Requirements. Chapter 5 Section 7 of the coal mining regulations provide that in-situ activities shall be planned and conducted to minimize disturbance to the prevailing hydrologic balance; prevent discharge of process fluid into surface waters; conduct air and water quality monitoring programs; and conduct all activities in accordance with the performance standards in Chapter 18 (in-situ mining standards), Chapter 7 (underground mining performance standards), and Chapter 4 (surface mining performance standards).

Chapter 18 requires annual reports, including all information required by statute under 35-11-411 WEQA as well as reports of the total quantity of recovery fluid injected and the total quantity extracted, monitoring results (including descriptions of all excursions), updated potentiometric surface maps of all aquifers that are or may be affected by the mining operation, and supporting data concerning ground water restoration.

Mechanical Integrity. The mining plan prepared by the owner or operator and approved by LQD and WQD must include a schedule and procedures for checking mechanical integrity.

Financial Responsibility. Bonding requirements in the WEQA (§§ 35-11-417 to 35-11-424) are also applicable to in-situ well operations (35-11-426 WEQA). The bond is required to equal the estimated cost of reclaiming affected land and restoring any ground water disturbed by in-situ mining during the first year of the permit. The bond will generally not be less than $10,000.

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