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National Energy Technology Laboratory

State Oil and Natural Gas Regulations Designed to Protect Water Resources

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GROUNDWATER PROTECTION COUNCIL

NETL

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Forward

The purpose of oil and natural gas regulations is to establish the framework within which regulatory programs insure that protection of the environment, especially water, is given the highest consideration with respect to the development of oil and gas resources.

While regulations are not the sole measure of regulatory effectiveness, they are an indicator of regulatory intent. They form the backbone of the regulatory program. Without regulations there would be little if any control over processes with the potential to create environmental harm.

Programmatic elements implemented in conjunction with regulatory language form the basis for an effective regulatory program. The reader should keep this in mind and consult each state regulatory agency website or speak with appropriate state agency staff, before concluding that a particular area is not addressed by a particular state. For example, New York's Department of Environmental Conservation (DEC) relies on statutory authority and regulation, but also utilizes an environmental review process, technical guidelines and special permit conditions to ensure safe and environmentally protective development of oil and gas resources. New York's broad statutory powers are conveyed in Article 23 of the Environmental Conservation Law. Rules and regulations contained in 6NYCRR Parts 550-559 establish permitting practices and safeguards such as well setbacks from structures, roads, surface water bodies and streams. However, the DEC's Division of Mineral Resources also reviews all oil and gas drilling permits in accordance with the State Environmental Quality Review Act (SEQRA) to ensure that the environmental impact of resource extraction will be mitigated to the greatest extent possible. Further, a Generic Environmental Impact Statement (GEIS) completed in 1992 evaluates potential environmental impacts from oil and gas drilling and recommends mitigation practices. Regulatory elements such as these are designed to insure oil and gas operations are conducted in a manner that is both safe and environmentally protective.

The report you are about to read is designed to convey the intent of regulations enacted by states for the purpose of protecting water resources. Although the content of the report does not reflect the unanimous views of all members of the Ground Water Protection Council, it is offered as a general view of the GWPC member states.

Mike Paque
GWPC Executive Director

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EXECUTIVE SUMMARY

Over the past several years the GWPC has been asked, "Do state oil and gas regulations protect water?" How do their rules apply? Are they adequate? The first step in answering these questions is to evaluate the regulatory frameworks within which programs operate. That is the purpose of this report.

State regulation of oil and natural gas exploration and production activities are approved under state laws that typically include a prohibition against causing harm to the environment. This premise is at the heart of the regulatory process. The regulation of oil and gas field activities is managed best at the state level where regional and local conditions are understood and where regulations can be tailored to fit the needs of the local environment. Hence, the experience, knowledge and information necessary to regulate effectively most commonly rests with state regulatory agencies. Many state agencies use programmatic tools and documents to apply state laws including regulations, formal and informal guidance, field rules, and Best Management Practices (BMPs). They are also equipped to conduct field inspections, enforcement/oversight, and witnessing of specific operations like well construction, testing and plugging.

Regulations alone cannot convey the full measure of a regulatory program. To gain a more complete understanding of how regulatory programs actually function, one has to evaluate the use of state guides, manuals, environmental policy processes, environmental impact statements, requirements established by permit and many other practices. However, that is not the purpose of this study. This study evaluates the language of state oil and gas regulations as they relate to the direct protection of water resources. It is not an evaluation of state programs.

To conduct the study, state oil and gas regulations were reviewed in the following areas: 1) permitting, 2) well construction, 3) hydraulic fracturing, 4) temporary abandonment, 5) well plugging, 6) tanks, 7) pits, and 8) waste handling and spills. Within each area specific sub-areas were included to broaden the scope of this review. For example, in the area of pits, a review was conducted of sub-areas such as pit liners, siting, construction, use, duration and closure. The selection of the twenty-seven states for this study was based upon the last full-year list (2007) of producing states compiled by the U.S. Energy Information Administration.

In the area of well construction, state regulations were evaluated to determine whether the setting of surface casing below ground water zones was required, whether cement circulation on surface casing was also required, and whether the state utilized recognized cement standards. Attachment 3 is a listing of the programmatic areas and sub-areas reviewed.

After evaluation, each state was given the opportunity to review and comment on the findings and to provide updated information concerning their regulations. Thirteen states responded. These responses were incorporated into the study.

One of the most important accomplishments of the study was the development of a regulations reference document (Addendum). This document contains excerpted language from each state's oil and gas regulations related to the programmatic areas included in the study. Hyperlinks to web versions of each state's oil and gas regulations are included as well as some of the forms used by state agencies to implement those regulations. An web enabled version of the study (to be completed by September, 2009) will also contain numerous hyperlinked text segments designed to provide the reader with an easy and effective way to review references and regulations.

Key Messages and Suggested Actions:

Key Message 1: State oil and gas regulations are adequately designed to directly protect water resources through the application of specific programmatic elements such as permitting, well construction, well plugging, and temporary abandonment requirements.

Suggested Action 1: States should review current regulations in several programmatic areas to determine whether or not they meet an appropriate level of specificity (e.g. use of standard cements, plugging materials, pit liners, siting criteria, and tank construction standards etc…)

Key Message 2: Experience suggests that state oil and gas regulations related to well construction are designed to be protective of ground water resources relative to the potential effects of hydraulic fracturing. However, development of Best Management Practices (BMPs) related to hydraulic fracturing would assist states and operators in insuring continued safety of the practice; especially as it relates to hydraulic fracturing of zones in close proximity to ground water, as determined by the regulatory authority.

Suggested Action 2: A study of effective hydraulic fracturing practices should be considered for the purpose of developing (BMPs); which can be adjusted to fit the specific conditions of individual states.

Key Message 3: Many states divide jurisdiction over certain elements of oil and gas regulation between the oil and gas agency and other state water protection agencies. This is particularly evident in the areas of waste handling and spill management.

Suggested Action 3: States with split jurisdiction of programs should insure that formal memorandums of agreement (MOAs) between agencies exist and that these MOAs are maintained to provide more effective and efficient implementation of regulations.

Key Message 4: The state review process conducted by the national non-profit organization State Review of Oil and Natural Gas Environmental Regulations (STRONGER) is an effective tool in assessing the capability of state programs to manage exploration and production waste and in measuring program improvement over time.

Suggested Action 4: The state review process should be continued and, where appropriate, expanded to include state oil and gas programmatic elements not covered by the current state review guidelines.

Key Message 5: The implementation and advancement of electronic data management systems has enhanced regulatory capacity and focus. However, further work is needed in the areas of paper-to-digital data conversion and inclusion of more environmental data is needed.

Suggested Action 5: States should continue to develop and install comprehensive electronic data management systems, convert paper records to electronic formats and incorporate widely scattered environmental data as expeditiously as possible. Federal agencies should provide financial assistance to states in these efforts.

1. Introduction

The year 2009, marked the 150th anniversary of the drilling of the first oil discovery well in the nation; which was drilled by Colonel Edwin Drake in Titusville Pennsylvania. This well marked the first time in U.S. history that anyone intentionally drilled for oil. Over a century later a healthy and sustainable domestic oil and natural gas production sector is still critical to the economic growth and stability of the U.S. From the oil shale beds in the Rocky Mountains to the Outer Continental Shelf oil and gas deposits; the tight shale gas zones in numerous states, to the oil and gas reservoirs underlying the Arctic National Wildlife Refuge, the prospect of drilling for and producing oil and gas has raised both hopes and concerns. Hopes that someday these resources will help the U.S. reduce or eliminate its dependence on foreign sources of oil and gas, and concerns that the subsequent exploration and development will not be tempered by sensitivity to the needs of the environment. This study looks at the regulatory language designed to regulate oil and gas in a way that does not adversely affect an even more vital natural resource -- water.

To fully understand the framework within which oil and gas activities are regulated we must first understand the different ways in which regulatory agencies function from state to state. We must also understand the nature of mandated responsibility to each agency within a state. For example, in many states, authority over one or more aspects of oil and gas operations is shared by an oil and gas agency and a water quality or pollution control agency. Under such circumstances, the effectiveness of regulatory programs can depend upon the ability of personnel in one agency to work with their counterparts in another agency. Further, while some states utilize regulations, policies, procedures, manuals and BMPs to implement a regulatory program, other states are limited solely to applying approved regulatory language. Many states utilize Best Management Practices; which act as important guides to operators but which may or may not be enforceable within the confines of the state's oil and gas regulatory program. Regardless of their value or effectiveness, BMPs do not constitute true regulation unless they are integrated into a regulatory regime. Otherwise BMPs are voluntary compliance tools that lack a means of enforcement.

Since the principal purpose of this study is to identify, quantify and assess the relative value of state oil and gas regulations, and not to evaluate the effectiveness of individual programs, any assessment of their effectiveness necessarily is based upon the principal that states intend to implement those regulations they approve. Consequently, if a regulation is formally approved, it constitutes a requirement on the regulated community, regardless of the methods by which it is enforced.

Some have suggested that the dual responsibilities of resource conservation and environmental protection are incompatible and that an oil and gas agency may be more interested in the production of petroleum resources than in environmental protection. This perception may have had some validity until the 1960's, but is no longer true, as the progression of water protection regulations implemented during the past fifty years demonstrates. In reality, resource conservation laws led to the development of regulations that were rooted in practical, implementable actions. This understanding of conservation regulation was instrumental in the development of environmental requirements that are tied to practical rather than theoretical concepts.

2. Selection of Study States

The Energy Information Administration (EIA) reported that in 2007 there were thirty-three states with either oil or natural gas production. Of these thirty-three states, twenty-seven represented more than 99.9% of all oil and natural gas produced in the U.S. Since it was not possible to assign a weighted value to each oil or natural gas producing state, it was necessary to neutralize the disproportionate effect that states with very minimal production would have had on the data analysis. This was accomplished by removing any state which accounted for less than 0.1% of both oil and natural gas production. Consequently, twenty-seven states are included in the study.

The following is a list of hyperlinks to the pertinent websites of the states included in the study.

Alabama State Oil and Gas Board
Alaska Oil & Gas Conservation Commission
Arkansas Oil and Gas Commission
California Department of Conservation, Division of Oil, Gas and Geothermal Resources
Colorado Oil and Gas Conservation Commission
Florida Geological Survey, Oil and Gas Section
Illinois Department of Natural Resources, Division of Oil and Gas
Indiana Department of Natural Resources, Division of Oil and Gas
Kansas Corporation Commission, Conservation Division
Kentucky Environmental and Public Protection Cabinet, Division of Oil and Gas Conservation
Louisiana Department of Natural Resources, Office of Conservation
Michigan Department of Environmental Quality, Office of Geological Survey
Mississippi State Oil and Gas Board
Montana Department of Natural Resource Conservation, Board of Oil and Gas
Nebraska Oil and Gas Conservation Commission
New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Division
New York Department of Environmental Conservation, Division of Mineral Resources
North Dakota Industrial Commission, Department of Mineral Resources, Oil and Gas Division
Ohio Department of Natural Resources, Mineral Resources Management Division
Oklahoma Corporation Commission, Oil and Gas Conservation Division
Pennsylvania Department of Environmental Protection, Bureau of Oil and Gas Management
South Dakota Department of Environment and Natural Resources, Minerals and Mining Program, Oil and Gas Section
Railroad Commission of Texas, Oil and Gas Division
Utah Department of Natural Resources, Division of Oil, Gas and Mining
Virginia Department of Mines, Minerals and Energy, Division of Gas & Oil
West Virginia Department of Environmental Protection, Office of Oil and Gas
Wyoming Oil and Gas Conservation Commission

3. Background and Scope

Throughout most of the 20th century the increased demand for petroleum products resulted in a comparable increase in oil and gas exploration and production (E&P) in the United States. In the early days of oil and gas production, the primary emphasis in regulation was on the prevention of waste and the protection of land/royalty owner mineral correlative rights. Most state regulatory programs were originally mandated by their legislative bodies to provide mineral rights owners the opportunity to develop their resources. The programs were also charged with the task of determining appropriate spacing patterns and establishing monthly or daily producing rates, called allowables, for wells within a producing field. These were established to reflect the petroleum supply and demand balance of the nation and, thus, prevent waste of petroleum resources in accordance with conservation and sound reservoir management practices. As a result many states enacted conservation laws to prevent premature abandonment of recoverable oil and gas resources. The history chapter of the report discusses the progression of oil and gas regulation from the relatively narrow property rights and conservation philosophy of the early 20th century to the comprehensive and more environmentally focused programs that have developed over the past fifty years.

This report focuses on the formal oil and gas regulations designed to directly protect water resources. The report does not contain information about other regulatory program elements such as periodic inspections, enforcement and financial assurance. While vital to the overall success of a regulatory program, these elements are used to help assure compliance with the regulatory requirements. However, data management is discussed because the ability to acquire, analyze and present data gives the regulatory agency the capability to focus its efforts in a manner that directly protects water resources.

With respect to the direct protection of water resources, this report focuses on the following regulatory activities:

Permitting
Well Construction
Hydraulic Fracturing
Temporary Abandonment
Well Plugging
Tanks
Pits
Waste Handling and Spills

The GWPC reviewed the regulations of the twenty-seven oil and gas producing states shown in Figure 1. The findings of this review were provided to each state for verification. Thirteen of the twenty-seven states responded to the verification request.

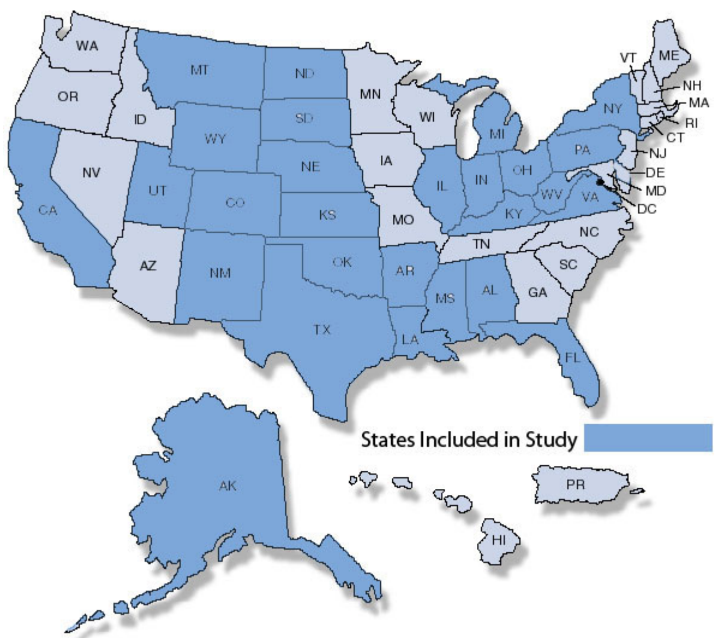


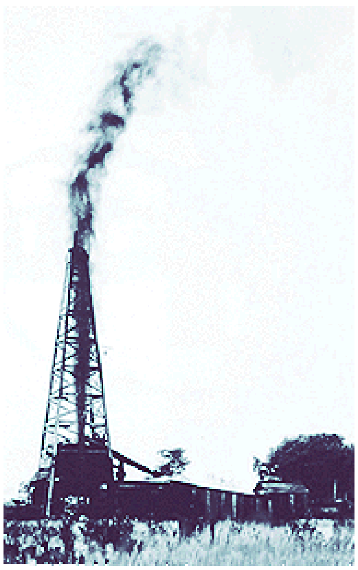
Figure 1 Map of the states included in the study

Although elements of the Underground Injection Control (UIC) program are mentioned in the report, as they relate to specific regulatory topics such as waste handling, actual state UIC regulations were not included. To properly review the UIC regulations would require a detailed analysis that was not within the scope of the study.

There is a great deal of variation between states with respect to defining protected ground water. The reasons for these variations relate to factors such as the quality of water, the depth of Underground Sources of Drinking Water (USDWs), the availability of ground water and the actual use of ground water. For example, the EPA establishment of a federal standard of 10,000 parts per million (PPM) as an upper limit for Total Dissolved Solids (TDS) content in ground water for the purposes of defining it as a USDW[9] was related to state definitions of fresh water dating back to the 1940s. As a result of state to state variations relative to protected ground water, it was not possible to apply a single precise term such as USDW throughout the report when talking about ground water protection. Therefore, it was decided to use the generic term "ground water" and to define it as ***"water contained in geologic media which has been designated by a state as usable for domestic, industrial or municipal purposes"***.

4. History of Oil and Gas Regulation

The evolution of water and environmental resource protection regulations governing oil and gas exploration, production and well abandonment did not follow the same pattern as other waste producing industries, including those related to the refining of oil into petroleum products, and other "downstream" petroleum operations. These "downstream" operations developed controls for preventing pollution to air, water, and land resources primarily in response to a series of federal pollution control acts passed by Congress between 1972 and 1990. However, the "upstream" (production) sector of the petroleum industry began to initiate water protection measures in response to individual state statutes and regulations enacted after 1900.



Oil Well Circa 1870

Most of these early regulations on well construction and plugging were not specifically designed to protect ground and surface water from the impacts of oil and natural gas production. Early casing and cementing programs of oil and gas wells were practical measures to prevent waters from adjacent non-productive formations and upper aquifers from flooding the oil-producing reservoir during drilling and subsequent production activities. Occasionally, the influx of alien waters was of such volume that drillers "lost the hole" prior to penetrating the target oil horizon. Consequently, these protection activities were incipient oil conservation measures that recognized flooding out of the oil reservoir created "loss" of a valuable salable product. This kind of thinking was evident in the technical books of the period. For example, in 1919, a geologist named Dorsey Hager wrote a book called "Practical Oil Geology".[1] In Chapter 9 of his book entitled "Water- Enemy of the Petroleum Industry, "Mr. Hager states "The danger of water in oil fields must not be underestimated. Water flooding is a danger often present where care is not taken in advance to protect the wells". In these early years the principal focus was on protection of the petroleum resource from the effects of water incursion and not on protection of water resources themselves.

Most oil producers of the early period (prior to 1935)believed that royalty payments to the landowner for the privilege of extracting oil or gas from beneath their land adequately compensated the landowner for any surface and water resource damages caused to the property. These damages included accidental spillage of oil or salt water, leakage of produced water from storage and disposal pits and loss of agricultural land taken out of production by the occupancy of property by oil field related equipment, structures, or around the working vicinity of each well. Prior to the 1940's, pollution to ground water from activities at individual tank battery locations to the extent where fresh water aquifers would be rendered unusable for a long period of time was not a concept widely understood by the oil industry, landowners or state regulatory agencies. Even landowners who had experienced considerable damage to their farms first viewed surface pollution as a necessary evil and an inherent part of the oil or gas production process.

A major portion of this chapter portrays how states legislative bodies responded to an increasing concern by landowners, farmers and municipal officials that water and land resources were being unnecessarily contaminated by oil field practices. A historical perspective also shows how state oil and gas environmental regulations have been philosophically influenced in some ways by of the influx of Federal environmental laws during the past thirty-five years in some ways, but not by others.

A. Prior to 1935; The Early Years

From the time the first documented oil well was drilled in Pennsylvania in 1859 by Colonel Drake to the early 1930s, the exploration and producing industry generally proceeded without much formal regulation, either at the state or federal level. New York required the plugging of abandoned wells as early as 1879. Ohio reported enacting the first law for regulating methods used to case and plug oil and gas wells to prevent water from penetrating and contaminating the oil bearing rock in 1883. In 1890, Pennsylvania passed the first law requiring non-producing wells to be plugged in order to protect the integrity of the producing formation. In 1915, the Oil and Gas Division of the Oklahoma Corporation Commission (OCC) was given exclusive jurisdiction over all wells drilled for the exploration and production of oil and gas and in 1917, the OCC was given authority over related ground water protection and mandated to develop procedures for plugging and abandonment. The Texas Railroad Commission was given similar authorities in 1917 and 1919 respectively. California enacted a plugging program in 1915 and added a ground water protection component in 1929. Other states set up oil and gas regulatory commissions, often without specific authority to promulgate regulations and where enforcement authority was only available under the general statutes and civil or county control.

Around 1931, a barrel of oil, which cost about 80 cents to produce, sold for as low as $.15[21]. This differential between supply and demand improved somewhat in ensuing years through the early 1930s. However, the potential for serious gluts of unmarketable oil remained and several governors, over the objections of oil producers, some state legislators and landowners, felt that some framework of government controls over the production of oil was necessary. The United States was then, and still is the only oil producing country in the world where minerals rights can be privately owned and the owner of the oil and gas rights can make a lease agreement with a company to extract hydrocarbons in return for a royalty payment based on a percentage of each barrel produced and sold.

B. 1935; Oil and Gas Conservation Is Born

In 1935, after several aborted attempts to come up with an acceptable concept for government intervention into the supply-demand roller coaster, six states, Oklahoma, Texas, Colorado, Illinois, New Mexico and Kansas formed the Interstate Oil Compact Commission (IOCC). In 1991, the organization changed its name to the Interstate Oil and Gas Compact Commission (IOGCC). The purpose of the IOCC was to promote conservation of oil resources through an orderly development of oil reservoirs. Companies would predict a market demand for their product and the state agency would then set an annual or semi-annual extraction allowable for each producing field (or producing horizon) based on the market prediction. Governor Marland of Oklahoma supported a concept addressing “economic waste” and believed that government should prorate production to obtain a fair price for crude oil. This concept was eventually changed to embrace the term “physical waste” and the six states ratified the Compact agreement.

One of the early efforts of the Compact was the development of a set of model regulations, which the states could use as a pattern to establish their own regulatory framework. Even though the model established a format for oil and gas conservation, the protection of ground water from pollution was carried as a secondary consideration in most regulations; particularly as the regulations applied to well construction and plugging. In the early 1960s the IOCC also developed a model for gas regulation similar to that created for oil in 1935.

From 1941 through the end of World War II, several state legislatures enacted moratoriums on the enforcement of any environmental regulations and many conservation practices controlling supply and demand due to the increased need for oil for the war effort. In late 1941, the beneficial effect of conservation in the late 1930s had been proven and the United States had a surplus capacity of about 1 million barrels of oil, approximately 80 percent of which was produced from Compact states. By 1945, the IOCC had grown in membership to 17 states and was a sustaining force in providing models for oil and gas producing states to follow in promulgating regulations.

C. 1945 to 1970: The Years of U.S. Oil Production Dominance

Throughout the period 1946 to 1960, most oil and gas producing states established a regulatory agency to enforce oil and gas conservation practices. Still, the environmental protection aspects of the oil regulatory picture developed sporadically. State statutes regarding pollution abatement and control of oil field practices and waste emanated from individual events rather than from an overall "welfare of the nation" impetus. Kansas, for example, gave its Board of Health (not the Corporation Commission) authority in 1946 to issue orders against oil field brine disposal pits that were causing salt water pollution, but it wasn't until January 1958 that the Board could issue permits for acceptable pit usage and deny permits for those deemed to cause potential pollution. Texas adopted "no-pit" rules in the late 1960s and several other states developed a stricter approach to how long produced fluids could be retained in pit. The concern over pit usage stemmed from a realization that these so-called "produced water evaporation pits" were little more than unsealed seepage pits and, as a result, domestic water wells were being contaminated with salt water.

D. The Environmental 1970s and 1980s

The 1970s brought the nation's environmental consciousness to the forefront. The passage of the Federal Water Pollution Control Act (FWPCA) in 1972 sent the message that the discharges of pollutants to the nation's waterways, estuaries and drainages, even intermittent ones, was no longer acceptable and discharges of specific inorganic pollutants were to be regulated either by state or federal permit. Congress authorized formation of the U.S. Environmental Protection Agency (EPA) to implement the FWPCA and successive environmental and water resource protection acts. Section 311 of the FWPCA and its successor, Clean Water Act (CWA) of 1977, elevated the consequence of accidental spillage of oil from a producing lease to a finable offense when the oil entered a flowing stream. The non-reporting of an oil spill was also a finable offense. Another part of CWA required containment dikes around tank batteries and oil storage facilities to prevent releases of oil to "navigable streams", which by definition included almost every intermittent upper reach of a stream if it connected to a potential flowing watercourse. This program, called the Spill Prevention Control and Countermeasures (SPCC) was administered under the direct implementation authority of EPA. Prior to FWPCA, most state oil and gas regulatory agencies required operators to contain, report, and clean up serious oil spills on water. However few operators were fined unless they refused to obey a state agency directive. EPA's enforcement of the SPCC program was sporadic throughout the first twenty years of the FWPCA and CWA and its overall impact on day-to-day oil and gas operations was minor. The CWA, however, marked the first time that the oil and gas producing industry was subject to direct dealings with a federal agency on environmental protection issues.

In 1974, Congress passed the Safe Drinking Water Act (SDWA); which authorized EPA to promulgate regulations for wells used to inject fluids into subsurface formations, including those used for either disposal of excess produced water or injection of produced water to increase recovery of oil. This section of the SDWA was called the Underground Injection Control (UIC) Program. Between 1982 and 1990, twenty oil producing states applied for and received primary enforcement authority (primacy) from EPA to administer the program under Section 1425 of SDWA. Delegation of authority for this program to the states allowed those with longstanding oil and gas regulatory programs to demonstrate that their programs were equally effective in protecting ground water as those promulgated and administered by EPA under Section 1422 of SDWA. The major initial impact of the UIC program was that operators had to verify the mechanical integrity of each of their injection wells once every five years. Prior to the UIC program, most regulatory agencies only required operators to test an injection well if it was known or suspected to be leaking.

The 1970s also marked the beginning of the decline in domestic oil production. Some landowners, who were actively engaged in agriculture, began to view the oil production on their acreage with its declining productivity as a nuisance, rather than a blessing. The state oil and gas regulators received increasing demands from landowners and tenants to have operators plug wells that were idle and appeared to be no longer productive. Many states set up "temporarily abandoned" or "idle" well programs that required operators to monitor the mechanical integrity and certify annually that these idle wells had a future purpose.

In the 1980s and particularly after the 1986 depression in the industry, several states (Kansas, Texas, California and others) received legislative authorization to establish dedicated funding to contract the plugging of abandoned wells. The use of these abandoned or "orphan" well plugging funds resulted in the permanent closure of thousands of wells that might have posed a threat to the environment.

Congress passed the Resource Conservation and Recovery Act (RCRA) in 1976 which gave EPA authority to regulate the disposition and disposal of those substances, which by a preset definition, were declared to be hazardous. Fluids produced during E&P of oil and gas were originally excluded from RCRA and set aside for further study. In 1988, the EPA Administrator issued a Regulatory Determination that wastes produced in connection with oil and gas (E&P) operations would continue to be regulated by the states and would be "exempt" from the RCRA Subtitle C regulatory regime. In response to this decision, IOGCC committees developed a set of environmental program guidelines for states to use in strengthening their oil and gas waste management programs (other than the UIC program) and beginning in 1991, the IOGCC began using state review committees comprised of state oil and gas regulators, state environmental regulators, major and local oil and gas producers and members of the environmental advocacy organizations to systematically review state oil and gas environmental regulatory programs against the guidelines. This process, called "state review" will be discussed further in Chapter 6.

E. 1990-2008: The Era of Environmental Regulation Refinement

The last two decades have provided new environmental regulatory challenges to oil and gas. Many states formed separate departments to administer overall environmental regulations because of the programmatic shift in emphasis toward protection of water and land resources and the special technical knowledge needed to implement programs. Such changes provided better coordination of environmental permitting and field inspection activities and improved documentation of accountable actions to state legislatures, the public and the petroleum industry. Several states revised existing regulations concerning pits, tanks and well construction during this period to reflect the latest technological, environmental and public policy needs of the state. There was also an increased level of enforcement against those operators who failed to maintain compliance. During this period, several states including Kansas, Oklahoma, Indiana, and Louisiana set up formal penalty schedules and operator suspension procedures to address habitual or flagrant non-compliance. The types of penalties that at one time only applied to Class II (oil and gas related) injection wells were now utilized for a whole range of environmental programs. Operators were also subjected to increases in well and/or performance bonding requirements and additional financial assurance requirements.

Since 1990, increased environmental awareness has resulted in the implementation of several new environmental programs. Some of these programs are listed below.

- the discovery of Coal Bed Methane (CBM) in Montana, Wyoming, the Four Corners area and the Black Warrior Basin of Alabama, brought the search for gas into some areas previously unexplored for hydrocarbons. Colorado and California, which had always regulated oil and gas at the state level under Home Rule statutes, now experienced increased pressure from citizens to have a significant part of regulation done through county or city ordinance, often in duplication to the mandate of the state regulatory agency. In 2008, Colorado revised its regulations to allow for expanded public participation in the permitting and environmental assessment of oil field sites. This participation included review by other state water protection agencies.

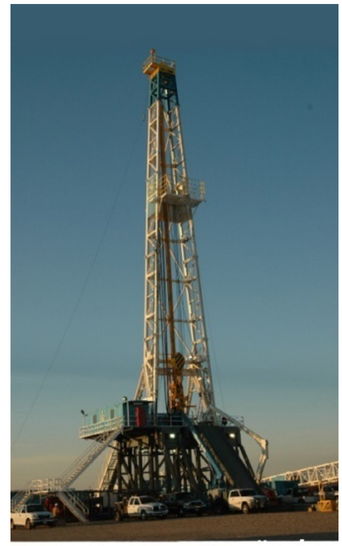
- in the mid-1990s citizens became concerned over the amount of Naturally Occurring Radioactive Material (NORM) that was being produced at some oil and gas lease locations. Some produced water had sufficient radium and other radioactive isotopes to develop a coating of precipitate in tubular goods and at pump connections. Operators were concerned when loads of salvage pipe were rejected by prospective buyers and were returned to them for disposal. As a result, some states such as Louisiana and Texas developed regulations governing the disposition of this pipe and other NORM materials and wastes.

- the Community Right-To-Know portion of Superfund (Section 312 of SARA Title III) of 1988 required oil operators to submit Material Safety Data Sheets (MSDS) reporting how much hydrocarbon was stored on-site at a lease facility. The state level administration of this program is usually administered by the principal state environmental agency rather than the oil and gas regulatory agency. This law also has a provision under Section 304 whereby the operator has to make changes in their facility design if a large release of hydrocarbons occurs.

- the Oil Pollution Act (OPA) of 1990 has had some impact on oil and gas production operations, primarily throughout the U.S. coastal areas of Louisiana, Texas, Mississippi and Alabama. This Act began as a reaction to the Exxon Valdez incident in Alaska in 1988 and required the use of double-hulled vessels to transport oil.

5. The Role of Current State Oil and Gas Regulation in Water Protection

A number of organizations have used public forums and published materials to assert that the oil and gas industry is "largely unregulated" at the state level. The documentation gathered and evaluated during the course of this study indicates otherwise.



Oil and Gas Drilling Rig

Each of the twenty-seven states studied has current state regulations governing E&P practices. Although current state oil and gas regulatory programs for water and environmental resource protection vary in scope and specificity, they invariably have the common elements necessary to ensure the development of oil and natural gas resources is accomplished in a manner designed to protect water resources. Regulatory requirements designed to protect water include specifications for permitting; drilling and construction of wells; handling of exploration and production waste fluids ,including produced water; temporary abandonment of wells; closure of wells; abandonment of wellsites, and other oil and gas activities. This chapter discusses specific elements of current state oil and gas regulations as they relate to the protection of water resources.

A. Permitting

All twenty-seven oil and gas producing states in the study have permitting requirements governing the locating, drilling, completion and operation of wells.

Authority to require permits for the drilling of oil, gas and service wells (injection wells and others) is typically delegated by the state legislature to an oil and gas division, commission or board. While agency heads are most often publicly elected or appointed by a governor, technical staff are usually engineers, geologists, or environmental scientists who are technically trained and qualified to review applications for both conservation and water resource protection purposes. Regardless of the agency configuration, each state implements regulations designed to prevent environmental contamination.

A person or company must submit an application to the regulatory authority and receive an authorization before drilling can begin. Permitting of wells serves many purposes. First, it expresses the intent of a person to drill a well for the extraction of oil or gas and provides the applicants drilling plan. Secondly, the permit application provides the regulatory agency with information such as the location, proposed depth, target formations and proposed construction of the well. Based on this information the regulatory agency can evaluate the proposed well to determine whether or not it meets the current regulatory requirements for drilling, construction and operation. In some cases, the permit covers not only the drilling of the well but the construction of the wellsite and the excavation of pits. For example, in Arkansas, the applicant is also required to submit a lease facility plan, including pit construction specifications. Lease facility plans must be approved by the Arkansas Oil Conservation Commission and Arkansas Department of Environmental Quality before drilling can begin.

While all twenty-seven states can deny a permit if the application contains insufficient information to make a technical determination, thirteen also have the authority to deny a permit for other reasons such as outstanding violations, lack of a state license etc… For example, in Ohio, "A Notice of Material and Substantial Violation (NOMSV) may cause permits to be denied; imminent danger is also cause for denial/suspension of a permit 1509.06 (F), (H)" and in Illinois an "Unabated Directors Order serves as a permit block to that permittee".

Of the thirteen states that responded to the request for verification, six reported either a geologist or engineer must review drilling permit application. Four states reported that agencies other than the oil and gas authority are involved in the permit review process either by requirement or upon request of the oil and gas agency. In addition to requirements for obtaining drilling permits, many states also have prior authorization requirements for a number of oil and gas activities including temporary abandonment and pit construction and use. However, the lack of a mechanism to obtain prior authorization for an activity does not mean the actual activity is unregulated. For example, while only five states required prior authorization to construct a tank battery, twenty-two states have some construction requirements including a containment dike around tank batteries.

B. Well Construction

1) Well Materials and Construction Requirements

4 1/2" production casing ready for wellsite delivery

Casing is typically steel pipe used to line the inside of the drilled hole (wellbore). The existing standard for oil and gas casing was established by the American Petroleum Institute (API) in Spec. 5CT. It specified the length, thickness, tensile strength and composition of casing and is still the most commonly used standard for the selection of oil and gas casing. Each full length of casing is often referred to as a casing string. Wells are typically constructed of multiple casing strings including a surface string and production string. These strings are set in the well and cemented in place under specific state requirements. The API in Spec. 10A also established standards for cement types. This standard listed a variety of oil and gas cements and cement additives. Although Class A (Portland) cement is the most common cement used in the oil and gas industry, the type of cement can be tailored to the individual well provided the state allows this degree of flexibility. For example, some wells penetrate formations that are difficult to cement because of their porous nature or due to a substantial water flow within the formation. In such cases, additives like cellophane flake and calcium chloride are sometimes added to the cement to seal off such zones, quicken the cement hardening process, and prevent washout of the cement.

(NOTE: The API's current standards documents, are referred to as "Recommended Practices". These are intended to replace specific standards such as Spec. 5CT. With respect to casing and cementing, API is presently developing a recommended practice called RP-65).

2) The Casing and Cementing Process

In general, the casing of oil and gas wells, whether vertical and horizontal, is accomplished in multiple phases from the largest diameter casing to the smallest. The first phase often involves the setting of conductor casing. The purpose of this casing is to prevent the sides of the hole from caving into the wellbore where it is drilled through unconsolidated materials such as the soil layers. After the conductor casing is set, drilling continues inside the conductor string to below the lowest ground water zone depending upon regulatory requirements. Surface casing is then run from the surface to just above the bottom of the hole. Cement is pumped down the inside of the casing, forcing it up from the bottom of the casing into the space between the outside of the casing and the wellbore, called the annulus. Once a sufficient volume of cement to fill the annulus is pumped into the casing, it is usually followed by pumping a volume a fresh water into the casing until the cement begins to return to the surface in the annular space. The cementing of casing from bottom to top using this method is called circulation. The circulation of cement behind surface casing insures that the entire annular space fills with cement from below the deepest ground water zone to the surface.

While nearly all states require the circulation of cement on surface casing, it is not a universal requirement. In some states cement is required across the deepest ground water zone but not all ground water zones. Regardless, such variations from the circulation of cement on surface casing are still designed to ensure that ground water zones are isolated from production zones.

Once the surface casing is set and the cement has had time to cure, the wellbore is drilled down to the next zone where casing will be set. In some states this results in the placement of intermediate casing. This casing string is run after the surface casing but before the production casing and is usually only required for specific reasons such as additional control of fluid flow and pressure effects, or for the protection of other resources such as minable coals or gas storage zones. For example, in New York, intermediate casing may be required for fluid or well control reasons or on a case specific basis; while in Wyoming, intermediate casing can be required where needed for pressure control.

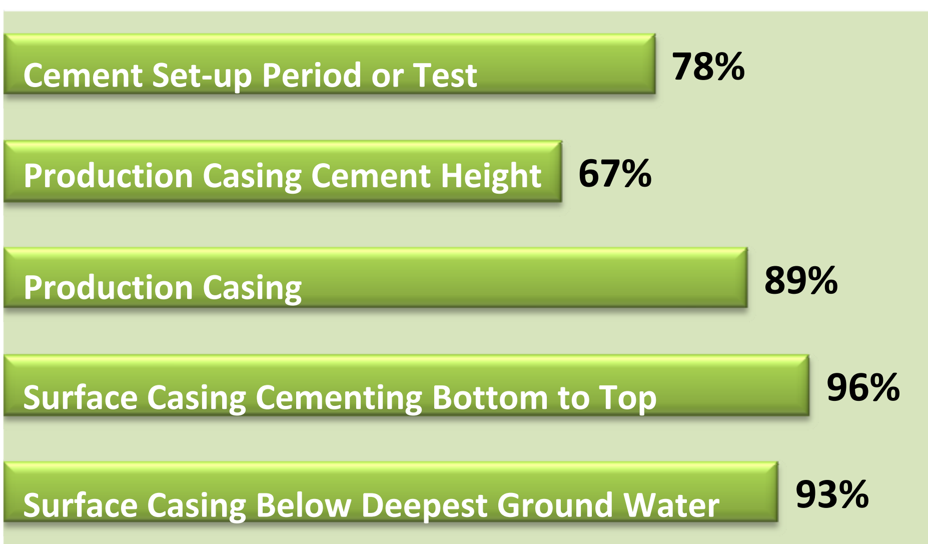
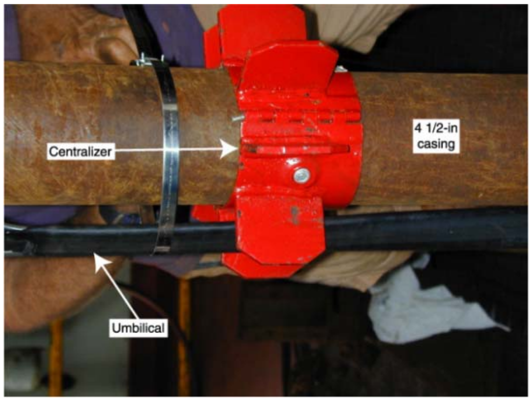


Figure 2 Casing and cementing requirements by percentage of states reviewed

Figure 2 shows that ninety-three percent of the twenty-seven states reviewed require surface casing to be set through the deepest ground water zone, and ninety-six percent also require cementing of the surface casing from bottom to top. Additionally, eighty-nine percent of the reviewed states require the setting of production casing to the top of or through producing zones with amounts of cement that range from bottom to top circulation to cementation at a defined height above each producing zone. Seventy-eight percent of the reviewed states require either a cement setup/ waiting period, or a cement integrity test as part of the cementation process.



Centralizer mounted on 4 ½ inch casing string[25]

After the surface and/or intermediate casing strings are set, the well is drilled to the target formation. Upon reaching this zone, production casing is typically set at either the top of, or into, the producing formation depending upon whether the well will be completed "open- hole" or through perforated casing.. The production casing is typically set into place with cement using the same method as the one used for surface and intermediate casing. In some cases, such as when the drill hole has deviated from vertical, casing centralizers like the one shown at left are used to assure the casing is centered in the hole prior to cementing so that cement will completely surround the casing. Although some states require complete circulation of cement from the bottom to the top of the production casing, most states require only an amount of cement calculated to raise the cement top behind the casing to a certain level above the producing formation. For example, in Arkansas, production casing must be cemented to two-hundred-fifty feet above all producing intervals.

There are a number of reasons why cement circulation from bottom to top on production casing is not always required including the fact that in very deep wells, the circulation of cement is more difficult to accomplish. Cementing must be handled in multiple stages; which can result in a poor cement job or damage to the casing if not done properly. Also, the circulation of cement on production casing prevents the ultimate recovery and potential reuse of the casing when the well is plugged and prevents the replacement of casing during the life of the well.

Some states also require the use of well tubing in addition to casings strings. Tubing, like casing, typically consists of steel pipe that follows the same standards as casing established by the API. The principal difference between casing and tubing is that tubing is not typically cemented into the well. A cross sectional diagram of a horizontal well equipped with casing and tubing is shown at right.

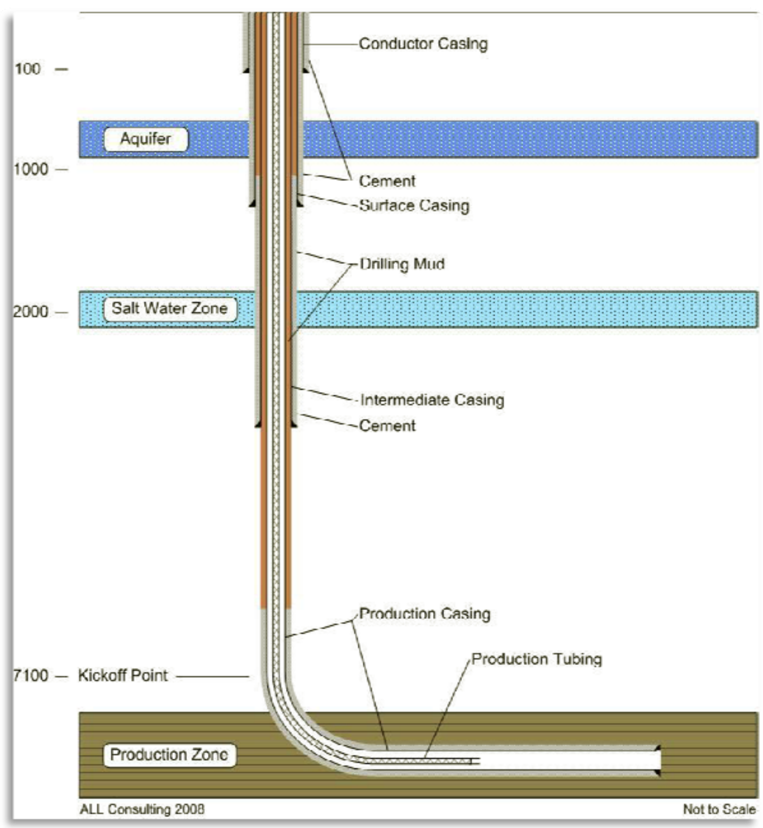


Figure 3 Diagram of a horizontal well constructed with casing and production tubing. Diagram courtesy ALL Consulting

3) The Relationship of Well Construction to Ground Water Protection

Casing strings are an important element of well completion with respect to the protection of ground water resources as they provide for the isolation of fresh water zones and ground water from the inside of the well. Casing is also used to transmit flowback fluids from well treatment. In this regard, surface casing is the first line of defense and production casing provides a second layer of protection for ground water. As important as casing is, however, it is the cementation of the casing that adds the most value to the process of ground water protection. Proper sealing of annular spaces with cement, creates a hydraulic barrier to both vertical and horizontal fluid migration. Consequently, the quality of the initial cement job is the most critical factor in the prevention of fluid movement from deeper zones into ground water resources. In some states it is common for state personnel to witness the running and cementing of casing strings, while in other states the submission of a completion report which details the amounts and types of casing and cement used in the completion of the well is considered sufficient evidence of proper well construction. In a few states such as Alaska, Michigan and Ohio an additional verification method using geophysical logs such as Cement Bond Logs (CBL) and Variable Density Logs (VDL) may be required. By measuring the travel time of sound waves through the casing and cement to the formation, the CBL shows the quality of bonding between the casing and the cement. The VDL performs a similar function to measure the bond between the cement and the borehole. By measuring the quality of the cement to casing and cement to formation bond, the sealing quality of the cement in the annulus can be evaluated. (See Exhibits 5 and 6, at the back of this report, for examples of CBL/VDL logs showing good cement bond and no cement bond/ free pipe).

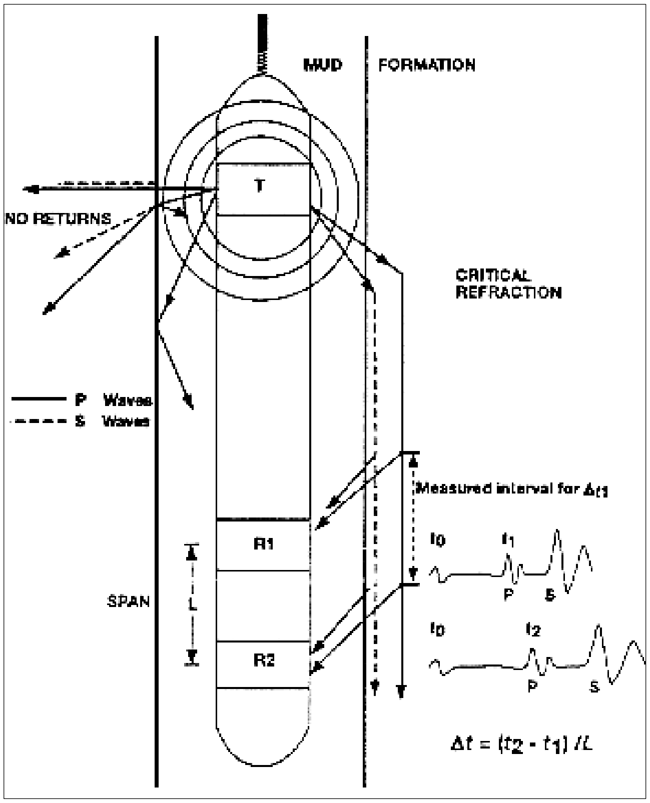


Figure 4 Operational diagram of Cement Bond Log tool

C. Hydraulic Fracturing

1) The Process of Formation Stimulation Using Hydraulic Fracturing

The first commercial application of hydraulic fracturing as a well treatment technology designed to stimulate the production of oil or gas likely occurred in either the Hugoton field of Kansas in 1946 or near Duncan Oklahoma in 1949. In the ensuing sixty years, the use of hydraulic fracturing has developed into a routine technology that is frequently used in the completion of gas wells, especially those drilled into unconventional reservoirs such as tight shale.

The process involves pumping fluid into a formation under sufficient pressure to create fractures in the rock matrix; allowing oil or gas to flow through the fractures more freely to the wellbore. By creating new pathways, hydraulic fracturing can exponentially increase oil and gas flow to the well. For example a single fracture job can increase the pathways available for fluid migration in a formation by as much as 270 times in a vertical well; and much more in a horizontal well.[24] The process of hydraulic fracturing can be a critical component of well development because, without it, there may be insufficient flow pathways for oil or gas to get to the wellbore.

The only alternative to fracturing the producing formations in reservoirs with low permeability would be to drill more wells in an area. However, given the costs of drilling, the risks associated with creating multiple new vertical pathways for fluid migration, and the fact that it could take very large numbers of wells located within a very small area to equal the production of even a single hydraulically fractured well, this alternative is neither physically nor economically desirable.

2) Fracture Fluids, Exposure Pathways and Isolation Techniques

a. Fracture Fluids

Fracture fluids may be based on either acid, gel, water, or oil. Most fracturing work is conducted using water based fluid. In addition to water, fracture fluids can contain a wide array of additives; each designed to serve a particular function. For example, in hydraulic fracturing of deep shale gas zones, the water is commonly mixed with a friction reducer to lessen the resistance of the fluid moving through the casing, biocides to prevent bacterial growth, scale inhibitors to prevent buildup of scale, and proppants, such as sand or ceramic beads to hold the fractures open[20]. This type of fracturing process is often referred to as a "slickwater" fracture. It is the use of additives, such as those listed above, that has raised one of the concerns about hydraulic fracturing.[6] A small number of potential fracture fluid additives such as benzene, ethylene glycol and naphthalene have been linked to negative health affects at certain exposure levels. However, most additives contained in fracture fluids including sodium chloride, potassium chloride, and diluted acids, present low to very low risks to human health and the environment.[19] A recent study conducted on behalf of the GWPC, with funding provided by the DOE, indicated hydraulic fracturing fluids for a nine-staged, sequenced, "slickwater" fracture treatment of a horizontal well in the Fayetteville Shale were typically 98 to 99.5% water by volume.[18] However, it should be noted that a toxicological evaluation of fracture fluid additives based on their relative proportions in flowback fluids was not a part of this study.

The best way to eliminate concern would be to use additives that are not associated with human health effects. While desirable, this is not yet possible in the case of some additives because the alternatives do not always have the properties necessary to provide the same degree of effectiveness as more traditional constituents. However, with respect to diesel fuel; which was cited as a principal constituent of concern by the Oil and Gas Accountability Project (OGAP) because of its relatively high benzene content[12] an agreement was reached to discontinue its use as a fracture fluid media in zones that qualify as USDWs. The discontinuation of diesel fuel use resulted from an effort that began at the 2002 annual meeting of the GWPC. At that meeting, the GWPC Board of Directors passed a resolution calling for a ban on the use of diesel fuel in the hydraulic fracturing of coalbed methane wells where drinking water sources were present. This was a landmark event which led to the development of a 2003 Memorandum of Agreement between BJ Services Company, Halliburton Energy Services, Inc., Schlumberger Technology Corporation and EPA (Attachment 4). In the memorandum, these companies; which were estimated to account for up to 95% of all fracture jobs conducted in the U.S., agreed to eliminate diesel fuel in hydraulic fracturing fluids injected into CBM production wells in USDWs within 30 days of signing the agreement. In 2008 the GWPC conducted a follow-up survey which found that in twenty-five states with potential coalbed methane production, the use of diesel fuel to hydraulically fracture coal beds that are USDWs was not occurring. (Attachment 1) Regardless of relative concentration, it is important that additives be prevented from entering ground water and creating unnecessary risks.

b. Exposure Pathways

Some reports critical of the hydraulic fracturing process have cited the exposure effects of additives that can be contained in hydraulic fracturing fluids without considering their relative availability via exposure pathways. For example, the GWPC/ DOE study, discussed previously, also found that depending upon the design of the fracture job and the specific formation dynamics involved, anywhere from 30-70% of fracturing fluids are returned to the surface through the well. The unrecovered treatment fluids are typically trapped in the fractured formation via various mechanisms such as pore storage and stranding behind healed fractures; thus isolating them from ground water.[3] The risk of endangerment to ground water is further reduced by other physical factors such as the:

- implementation of state well construction requirements;
- vertical distance between the fractured zone and ground water;
- presence of other zones between the fractured zone and the deepest ground water zone that may readily accept fluid; and
- presence of vertically impermeable formations between the fractured zone and the deepest ground water zone; which act as geologic barriers to fluid migration.

Additionally, proper surface fluid handling methods can significantly decrease the likelihood of environmental harm from or human exposure to hydraulic fracturing fluids. For example, once hydraulic fracturing fluids return to the surface, they are typically stored in tanks or lined pits to isolate them from soils and shallow ground water zones.

The ultimate fate of hydraulic fracturing fluids returned to the surface is often determined by the availability of treatment and disposal technologies such as on-site or municipal treatment facilities and injection wells. Underground disposal via injection wells under the jurisdiction of the UIC program is the most common method of disposal for used fracture fluid. However, prior to disposal, fluids are sometimes treated and re-used in subsequent fracturing. On-site treatment and surface discharge, though rarely used, is also a disposal option, where authorized by a state regulatory agency. Treatment in municipal wastewater facilities is also sometimes conducted, provided the fluid will not cause the facility to violate a drinking water standard. The use of these techniques reduces the risk of endangerment to water.

Until effective alternatives to other, traditional additives are in wide use, the best way to protect ground water is to isolate hydraulic fracture fluids from ground water zones. Consequently, the primary mode of regulating hydraulic fracturing involves the application of well construction requirements designed to seal the wellbore and prevent the movement of fluids into ground water.

c. Isolation Techniques

Since ground water contamination resulting from the flowback of fracture fluids returned to the surface through casing would require simultaneous failures of multiple barriers of protection such as casing strings and cement sheaths, the risk profile for such an event is low[18]. Therefore, the greatest risk of contamination of ground water by fracture fluids comes from the potential for fluids to migrate upward within the casing/ formation annulus during the fracturing process. The most effective means of protecting ground water from upward migration in the annulus is the proper cementation of well casing across vertically impermeable zones and ground water zones. Proper cementation creates the hydraulic barriers that prevent fluid incursion into ground water. The amount and placement of cement needed for this purpose will vary depending upon several factors including the:

- size of the casing/ wellbore annulus
- quality of cement ;
- depth, thickness and vertical permeability of formations between the fractured zone and ground water
- distance between the fractured zone and ground water;

In a 1998 survey of twenty-five state oil and gas regulatory agencies, conducted by the GWPC, twenty-four state programs said they had not recorded any complaints of contamination to a USDW that the agency could attribute to hydraulic fracturing of coalbed methane zones.[26] Since this survey was conducted, several citizens have alleged that their ground water has been contaminated by the practice of hydraulic fracturing. Most of these complaints appear to be related to hydraulic fracturing of coalbed methane (CBM) zones; which were in relatively close proximity to USDW's.

Depending upon the geologic setting, CBM wells are typically, though not always; much shallower than conventional oil and gas wells and many unconventional shale gas zones. In general the amount of vertical separation between an oil and gas producing formation and the deepest ground water zone in many parts of the country can be several thousand feet; while the separation of coalbed methane zones to ground water is sometimes only a few hundred feet or less. In some cases the CBM zones themselves may qualify as USDWs. Regardless, since EPAs 2004 study found no confirmed cases of contamination from the relatively shallow hydraulic fracturing of CBM reservoirs[3], it is not unreasonable to conclude that the risk of fracture fluid intrusion into ground water from the hydraulic fracturing of deeper conventional and unconventional oil and gas zones could be considered very low because:

- there is often significant vertical separation between the fractured zone and ground water zones, especially in the majority of deep shale gas plays[18];
- well construction requirements in most states include provisions for cementation above producing zones and across ground water zones;
- there are frequently layers of rock between the fractured zone and ground water zones that are capable of accepting fluid under pressure; which would lower the available fluid that could reach a ground water zone;
- there are also frequently layers of rock between the fractured zone and ground water zone through which vertical flow is restricted; thus serving as a hydraulic barrier to fluid migration;
- the use of advanced computer modeling in fracture design has increased the ability to predict the three dimensional geometry of fracturing; which lowers the likelihood of a fracture job extending into an unintended zone.[18]

3) Well Treatment Reporting

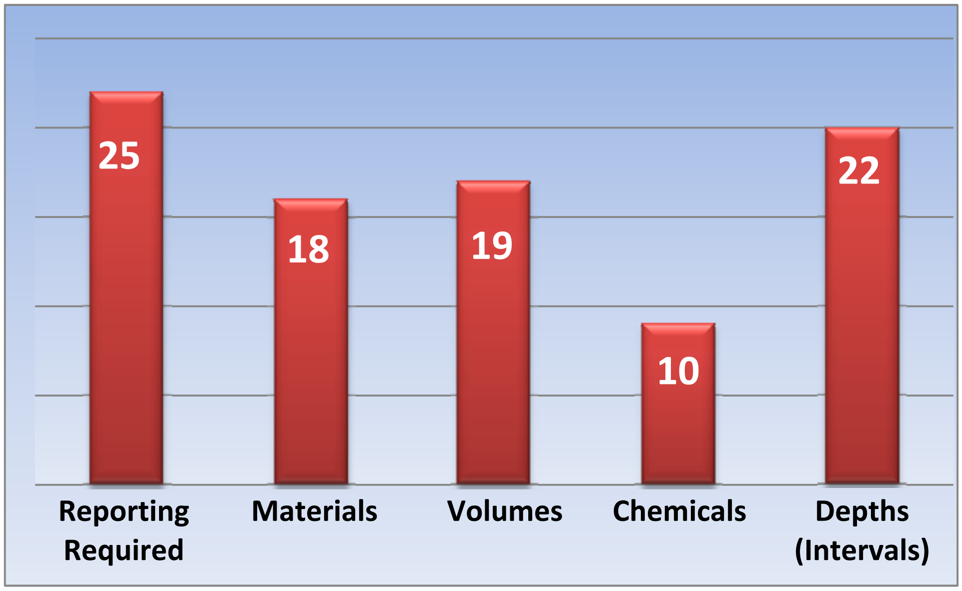


Figure 5 Well treatment reporting requirements by numbers of states

Twenty-five oil and gas agencies require the submission of well treatment reports within a time frame that typically ranges from thirty to sixty days. These reports are required under a variety of circumstances including initial well completions, re-completions, and in some cases for treatments alone. While requirements for reporting vary with respect to the amount of information listed, eighteen states require a list of the materials used, nineteen specify the volumes used, and twenty-two require reporting of the treatment depths (intervals). Ten states require a listing of chemicals or pressures used but none requires a listing of either the volume of fluid that flows back to the surface or an estimation of the volume of fluid that remains in the formation following the treatment.

D. Temporary Abandonment of Wells

Temporary abandonment (TA) allows oil and gas operators an opportunity to keep wells intact rather than plug them during periods when there may be no production from the well. This practice is common in many states. The primary purposes of allowing temporary abandonment are to prevent the plugging of wells that may have future economic value and to avoid the drilling of replacement wells.

Among the twenty-five states allowing TA status, twenty-four require an authorization from the regulatory agency before a well can be left idle. Since the principal issue that arises with respect to the protection of ground water from temporarily abandoned wells involves the ability of the well components to prevent fluid intrusion and migration, prior notification allows the regulatory agency an opportunity to review the history of the well including its construction, and to witness any tests run on the well to demonstrate integrity.

In addition to prior authorization, the review showed that twenty states require the operator to either:

- demonstrate integrity of the well by a casing pressure test or other means (some for initial TA status and others upon renewal); or
- construct and/ or maintain a well in a specific way. For example, renewal of TA status in Indiana requires an operator to either place a bridge plug in the well or demonstrate that the fluid level in the casing is one-hundred feet below the deepest USDW.

Figure 6 lists the TA requirements by numbers of states. These requirements are important because they help insure that upward migration of fluids that could threaten ground water is prevented while the well is idle. All but one of the states that allow TA, also have provisions for renewing TA status and nine set a limit on the total duration of time a well can remain on TA. However, provided well integrity can be demonstrated as part of the TA renewal process, allowances for long term TA status should not be a cause for concern.

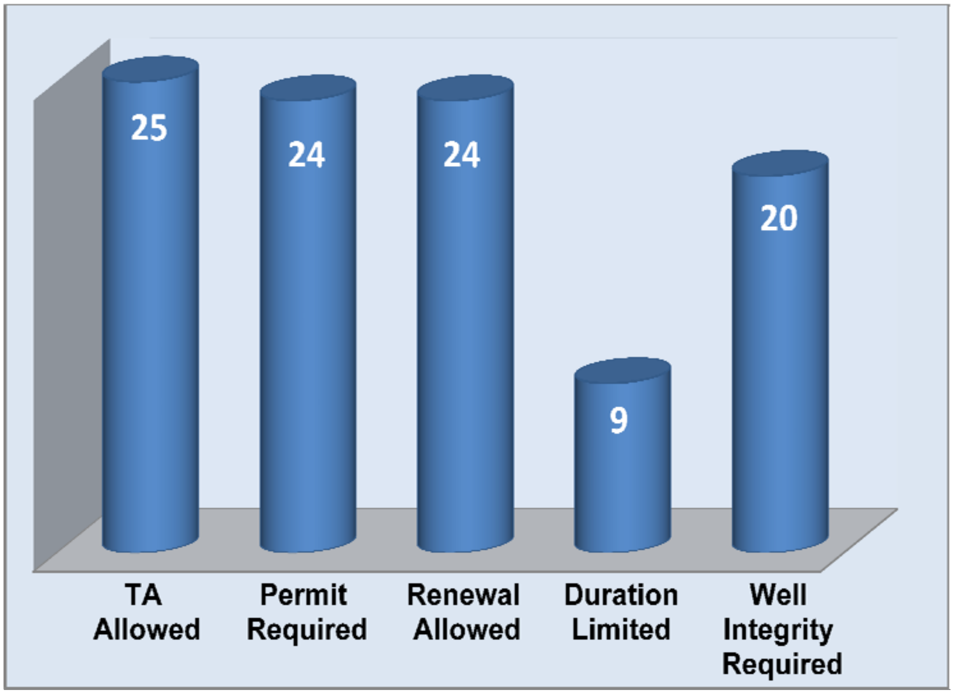


Figure 6 Temporary abandonment requirements by numbers of states

E. Well Plugging

The purpose of well plugging is to permanently seal the inside of the well and wellbore so that fluid cannot migrate from deeper to shallower zones or create reservoir problems through downward drainage. The process involves the placement of cement and other materials such as gels inside the well or wellbore in a manner that prevents the upward or downward migration of formation fluids. All twenty-seven states regulate the practice of well plugging to varying degrees. In most states very specific requirements on the materials and placement methods for plugs are used while in a few states the requirements are more general in nature. In twenty states operators must submit a plugging plan in advance. In twenty-two states a prior notice to the regulatory agency is required before a well can be plugged. This provides the agency with an opportunity to have field personnel witness the plugging to assure use of proper plugging materials and placement methods.

1) <u>Plugging Materials</u>

Wells are plugged using a variety of materials such as cement, bridge plugs, clay, gel, and other spacer materials such as drilling mud and water. Since the purpose of well plugging is to seal the wellbore, the competence, placement and verification of plugs are critical. Each type of plug has unique characteristics. For example, when properly mixed and placed, standard Class A (Portland) cement provides a strong, relatively impermeable plug. Conversely, while bentonite (clay) plugs are more ductile and tend to seal off minor leakage pathways better than cement, they are more prone to long term degradation and shrinkage, and do not have the strength of cement. Consequently, in most cases states will typically allow clay to be used as a spacer between cement plugs, but not as a

A sack of Portland cement will yield about 1.18 cu. ft. of cement primary plugging material. Cast iron bridge plugs (CIBP) provide a good well seal, especially when there is significant bottom hole pressure (BHP). CIBPs are also nearly impermeable. However, CIBP's are subject to corrosion over time and need to be capped with an appropriate cement plug to assure the long-term integrity of the plugged well.

2) Plugging Intervals and Methods

Most states require a combination of plugs at multiple vertical intervals to assure long term protection from fluid migration and to compensate for various downhole geologic and hydrogeologic conditions that might render the plugging materials ineffective.

As Figure 7 shows, twenty-two states require the placement of a cement bottom plug through and/ or above producing formations and the placement of a top plug across the deepest ground water zone. Additionally, seventeen states require the pulling or cementing in place of uncemented casing to assure cement is in contact with either the wellbore or cemented casing. Fourteen states also require that cement plugs be placed using a specific method such as the pump and plug (displacement) method or via dump bailing (See Figure 6). Both methods are designed to spot plugs over particular intervals and to assure the plug fills the space for which it was intended. The use of surface down pumping (bull heading) of cement plugs; which can lead to channeling of cement, though not specifically prohibited in most states, is excluded by a requirement to place plugs using displacement or dump bailer methods. When used in conjunction with bridge plugs, the placement of cement plugs by displacement and dump bailer methods allows the regulatory agency to ascertain the location of plugs.

3) Plugging Reporting

Twenty-six states require the filing of a plugging report. These reports detail the materials and methods used to plug the well including the plugging intervals, volumes and types of plugs used and the amounts of casing pulled or cemented in place.

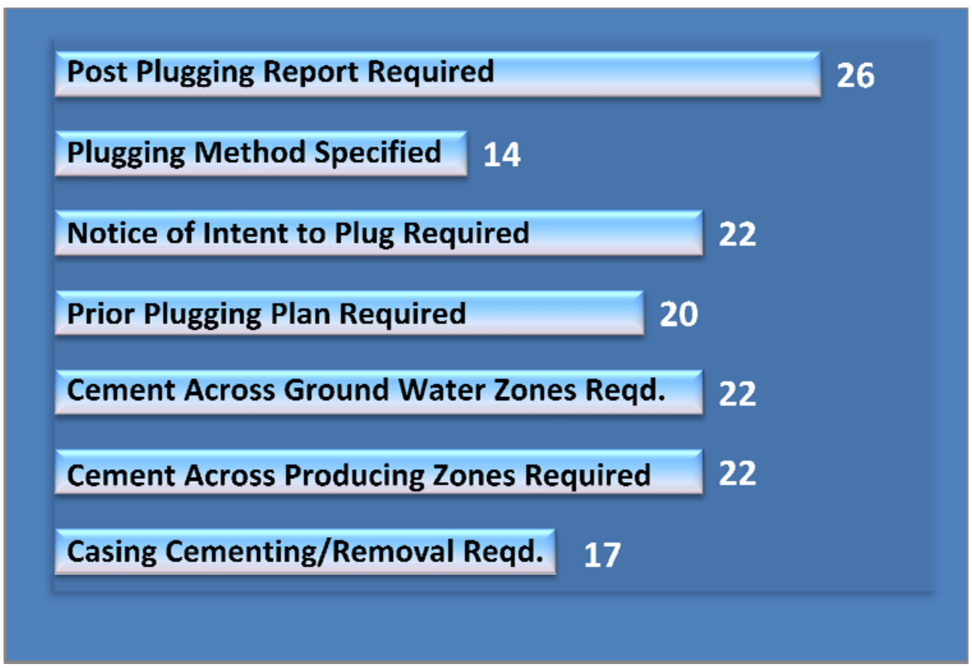


Figure 7 Well plugging requirements by numbers of states

Plugging reports are usually completed by the operator or operator's agent and must be submitted within a certain time following the conclusion of plugging. In some states a separate affidavit of plugging is required if a plug job is not witnessed by agency personnel. Under such circumstances, the state may often require the submission of "cement tickets" from the company that supplied the cement so the volumes used can be independently verified.

F. Tanks

Twin 210 barrel oil tanks inside containment dike

Tanks used for the storage of oil and produced water vary in material composition, placement configuration and size depending upon specific production needs. A group of tanks used to store oil and produced water is often referred to as a "tank battery" Where saltwater is not co-produced with oil, the tank battery typically consists of one or more oil storage tanks similar to the photo at left; which shows a pair of 210 barrel tanks surrounded by a containment dike. However, when saltwater is part of the production fluid stream, the tank battery also usually includes a gravity oil/ water separator, sometimes called a "gun barrel" and one or more water tanks for the storage of saltwater that has been separated from the produced oil/ water stream. In some cases additional tanks such as heater treaters are also present to process the oil.

Most states do not specify the materials to be used in the construction of tanks. However, five states do require tanks be constructed in a manner designed to hold the fluids being stored and two states (Colorado and Wyoming) utilize a particular standard. Colorado requires the use of Underwriters Laboratories (UL) or American Petroleum Institute (API) standards as applicable and Wyoming requires tanks to meet federal Spill Prevention Control and Countermeasures (SPCC) standards. Regardless, the general lack of a specific requirement such as an industry or technical standard in most states allows for the use of a multitude of materials such as plastic, wood, concrete, steel and fiberglass. While some materials are appropriate for the storage of particular types of fluids, others are not. For example, in some states, it is not uncommon for produced water to be stored in steel tanks. Since produced water is corrosive to varying degrees, storage in steel tanks can lead to leaks and tank failures over time. However, it is important to note that development of tank construction standards is evolving and more states are beginning to review their current standards with an eye toward implementing more specific requirements. For example, Colorado recently promulgated a rule change that includes a provision stating that replaced or newly constructed tanks must be "designed, constructed and maintained in accordance with the National Fire Protection Association (NFPA) Code 30 (2008 version)".

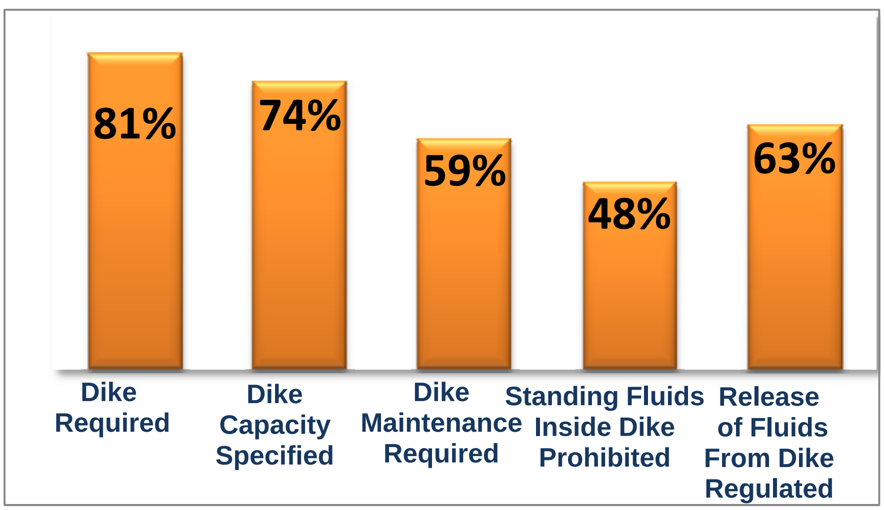


Figure 8 Containment dike requirements by percentage of states

To lower the potential for releases of stored fluids from tank leaks and failures, 81% of the reviewed states require tank batteries to be surrounded by a secondary containment dike.

These dikes, often referred to in regulations as firewalls, are designed to hold fluids that may escape from a tank. Further, 74% of the states requiring a containment dike also specify the capacity of the dike. These capacities ranged from one to one and a half times the capacity of the tank or tanks surrounded by the dike.

Although few states specify the permeability or holding time requirements for secondary containment systems, most require the dike be capable of "holding fluids", be maintained, and be kept free of fluids except during an event for which the dike was constructed. Finally, 63% of states specify that fluids within containment dikes be disposed of under specific requirements; including the requirement for a discharge authorization if fluids are to be released to the land surface (See Figure 8).

G. Pits

From the time the first oil and gas wells were drilled, pits have been used to hold drilling fluids and wastes. Although steel tanks and other above ground containment systems are sometimes required due to specific geologic conditions such as the presence of solution impacted limestone bedrock at the surface (referred to as karst), excavated pits are still the most common means of storing fluids during drilling and well operations. Today, pits are used for storage of produced water, for emergency overflow, temporary storage of oil, burn off of waste oil, and for temporary storage of well completion and treatment fluids. In nineteen states, use of a pit requires a prior authorization from the regulatory agency; and in some states, a separate permit is required for each functional pit use (e.g. drilling, fluid storage, emergency etc…). Nineteen states require the issuance of a prior authorization or permit before a pit is constructed or used, and sixteen also specify the duration of time for which a pit may be used. (See Figure 9)

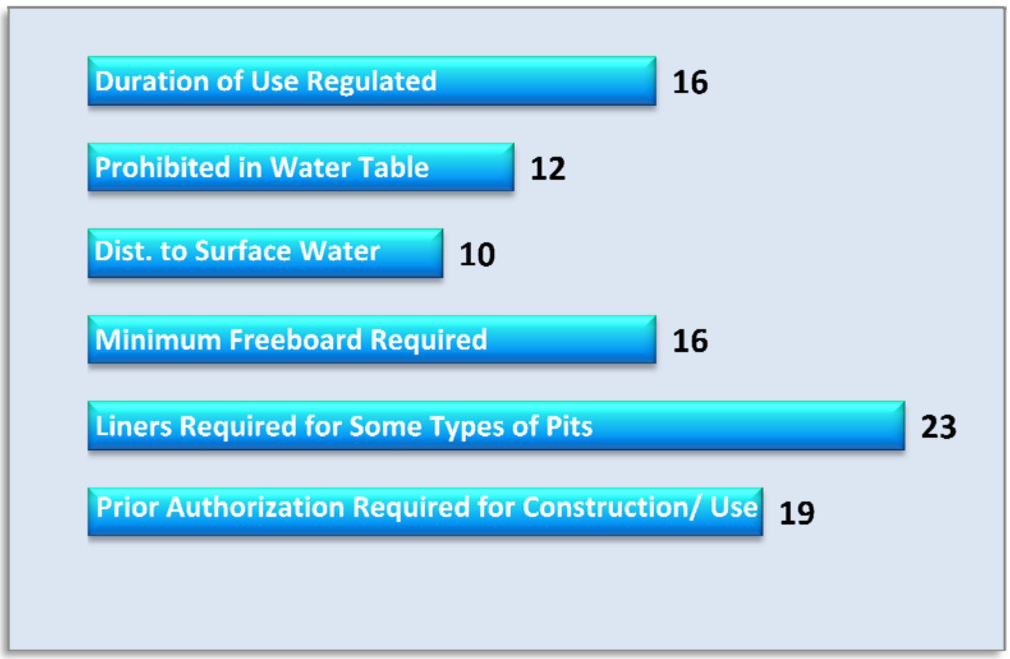


Figure 9 Pit requirements by numbers of states

The containment of fluids within a pit is the most critical element in the prevention of shallow ground water contamination. Depending upon the fluids being placed in the pit, the duration of the storage and the soil conditions, pit lining may be necessary to prevent infiltration of fluids into the subsurface. In twenty-three states, pits of a certain type or in a particular location must have a natural or artificial liner designed to prevent the downward movement of pit fluids into the subsurface. For example in Louisiana liners are required for produced water, onshore terminal and washout pits. In some states, liners are also required for emergency pits on a case by case basis.

Typically, pit liners are constructed of compacted clay or synthetic materials like polyethylene or treated fabric that can be joined using special equipment such as the seam welder shown at right. In addition to liners, ten states also require pits used for long term storage of fluids to be placed a minimum distance from surface water to prevent potential overflows that could result in an unauthorized discharge to water. In California, for example, pits may not be placed in areas considered "natural drainage channels". Twelve states also explicitly either prohibit or restrict the use of pits that intersect the water table. Further, sixteen states require fluids in pits remain a certain level below the top of the pit wall. This distance, referred to as the "freeboard" provides for a safety margin to prevent pit overflows in the event of significant rainfall.

Joining the seam of a synthetic liner

H. Waste Handling and Spills

Approximately 98% of all material generated from oil and gas E&P operations in the U.S. is produced water[8]. In 2006, based on a national average of 10 barrels of water to each barrel of oil produced[23], the total annual volume of water produced from oil and gas E&P operations exceeded 13.5 billion barrels. Given the volume and the frequently high concentration of dissolved solids that are in each barrel of produced water, it is important that these fluids be managed in a manner that prevents endangerment to surface or ground water. As previously discussed, produced water is typically stored at the surface in pits or tanks which are under the jurisdiction of the state oil and gas agency.

Storage is just one part of produced water management. The final disposition of produced water is also of critical importance to the protection of both surface and ground water. Advances in water treatment technology, including the use of filtration, reverse osmosis, decomposition in constructed wetlands, ion exchange and others, may eventually result in the widespread practice of using produced water for alternate purposes such as managed irrigation, land application and industrial processes.[7] Until such reuse practices of produced water attain general acceptance and wider use, the subsurface reuse and disposal of produced water via underground injection will remain the principal method of management. Injection of produced water is regulated by state oil and gas agencies and EPA through the Underground Injection Control (UIC) program. Of the twenty-seven states reviewed, twenty-three had delegated authority from the EPA for the Class II (oil and gas related) injection well program. The remaining eight Class II UIC programs were managed by EPA regional offices.

Vegetable irrigation using reclaimed produced water

The responsibility for regulating E&P wastes is sometimes divided between or shared by the state oil and gas agency and the state water quality or pollution control agency. For example, in at least nine states the handling of E&P wastes is controlled by more than one agency and in at least six states the same situation applies to the management of spills.

The jurisdictional authority for regulating E&P wastes varies and can be determined by factors such as whether a waste spill is on or off a lease, whether or not the waste is a RCRA Subtitle C exempt waste, or whether the spill has migrated into water. For example, under a Memorandum of Agreement with the Illinois Environmental Protection Agency the Illinois Division of Oil and Gas shares responsibility for spills of oil or produced water, when the spill enters surface water. A similar arrangement applies in

Indiana between the Division of Oil and Gas and the Department of Environmental Management. (See Attachment 7) In cases where wastes include non-exempt constituents or where spills enter water, states will often rely on the state water quality or pollution control agency to regulate the waste or supervise containment and cleanup of the spill. When waste spills are exclusively RCRA exempt and do not enter water, the oil and gas agency typically retains jurisdiction.

Under RCRA provisions, if an unused well treatment fluid is mixed with a used treatment fluid, the entire mixture could become non-exempt.[13] Regardless, twenty-six states regulate the surface management and application of wastes either through direct control by the oil and gas agency or through a point source discharge permit administered by either the state or federal government; depending upon the states National Pollutant Discharge Elimination System (NPDES) delegation status. For example, the application of wastes to land is regulated by the Wyoming Oil and Gas Commission if it occurs on a lease. However, off the lease, the same process is regulated by the Wyoming Department of Environmental Quality. In North Dakota small applications of waste on a lease are handled by the North Dakota Industrial Commission, whereas larger applications of waste, whether on or off a lease, come under the jurisdiction of the North Dakota Department of Health.

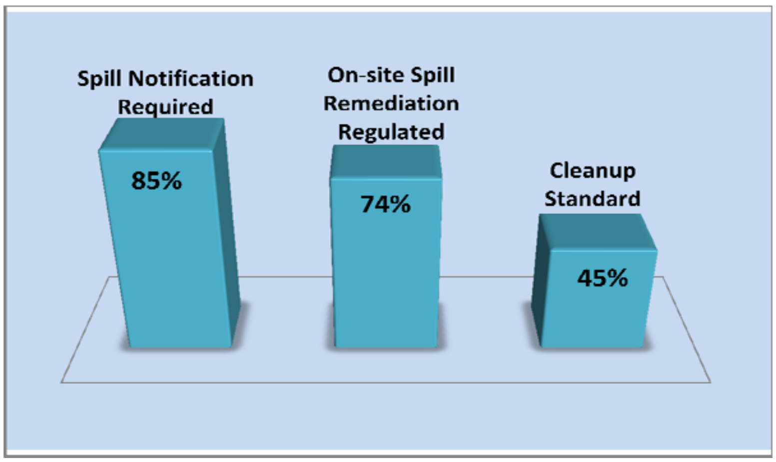


Figure 10 Oil or saltwater spill management requirements by percentage of states reviewed

Road spreading of some E&P wastes is one method of on-site management that is commonly allowed. This technique is typically limited to the application of drilling wastes such as mud and tank bottoms; which are primarily sand but can contain up to 19% oil by volume.[16]

A 2000 EPA report covering Crude Oil Tank Bottoms and Oily Debris stated that "when conducted in accordance with state requirements, roadspreading can be considered a beneficial use of a material that would otherwise require disposal."[15] Further, another 2000 EPA report covering Completion and Workover Wastes reported that "no incidents were identified where roadspread completion/ workover fluids or other completion/ workover wastes were responsible for environmental damages."[14]

Although twenty-three state oil and gas agencies require the reporting of E&P waste spills within a specified time period, this does not mean the oil and gas agency will retain jurisdiction over the management of the spill. In at least four states, spills are managed under split jurisdiction. For example, as previously noted, in Illinois and Indiana if an oil or produced water spill enters water, it falls under the jurisdiction of the state water quality or pollution control agency. As Figure 10 shows, 85% of the reviewed states require the operator to notify the oil and gas agency in the event of a spill and 74% of on-site spill remediation is regulated by the oil and gas agency.

Regardless of agency jurisdiction, 45% of states have a specific cleanup standard related to spills. For example Colorado's currently revised rule uses Table 910-1 to establish the cleanup standards for organics and inorganics in soil and ground water including allowable concentrations for Total Petroleum Hydrocarbons, Benzene, Toluene, Etheylbenzene and Xylene, Total Dissolved Solids (TDS),Chlorides and various metals.

6. The RCRA Exemption and State Review

A. History of the RCRA Exemption

The 1976 Resource Conservation and Recovery Act (RCRA) language instructed EPA to develop regulations for the identification and management of hazardous waste. The following is a timeline of the actions that provided for the current exemption of oil and gas E&P wastes from the Subtitle C (hazardous waste) provisions of RCRA:

December 18, 1978—EPA published the first set of proposed hazardous waste management standards in the Federal Register (43 FR 58946). This FR notice included a proposal to exempt six categories of "special wastes" from the RCRA Subtitle C regulations until further study could be completed. "Oil and gas drilling muds and oil production brines" were included as two of the six special wastes.

October 12, 1980—Congress enacted the Solid Waste Disposal Act Amendments of 1980 (Public Law 96-482) which amended RCRA. Among the amendments, Section 3001(b)(2)(A)—frequently referred to as the Bentsen Amendment—temporarily exempted "drilling fluids, produced waters, and other wastes associated with the exploration, development, and production of crude oil or gas." At the same time, Section 8002(m) required EPA to study these wastes and submit a Report to Congress evaluating the status of their management and potential risk to human health and the environment by October 1982. EPA was also required to make a regulatory determination (within six months of the completing the Report to Congress) as to whether these wastes warrant regulation under RCRA Subtitle C or some other set of regulations.

August 1985—The Alaska Center for the Environment sued EPA for its failure to conduct the required study and submit its findings to Congress. EPA entered into a consent order obligating it to complete and submit the Report to Congress by August 31, 1987.

December 1987—EPA submitted a three-volume Report to Congress on the Management of Waste from the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy (EPA530-SW-88-003, Volumes 1-3).

July 6, 1988—The EPA Administrator issued a Regulatory Determination for Oil, Gas, and Geothermal Exploration, Development and Production Wastes, July 6, 1988 (53 FR 25466) (PDF) which stated that EPA believed the regulation of oil and gas exploration and production wastes under RCRA Subtitle C was not warranted. Rather than subjecting E&P waste to the Subtitle C provisions, EPA planned to implement a three-pronged strategy to address the issues posed by these wastes by improving federal programs under existing authorities such as Subtitle D of RCRA, the Clean Water Act, and the Safe Drinking Water Act; working with states to encourage changes and improvements in their regulations and enforcement; and working with Congress to develop any additional statutory authorities.

March 22, 1993—The EPA Administrator issued a Clarification of the Regulatory Determination for Wastes from the Exploration, Development and Production of Crude Oil, Natural Gas and Geothermal Energy, March 22, 1993 (58 FR 15284) (PDF) which clarified the regulatory status of wastes generated by the crude oil reclamation industry, service companies, gas plants and feeder pipelines, and crude oil pipelines. EPA only provided further clarification on the status of these wastes under the exemption and did not alter the scope of the original exemption in any way.

October 2002—EPA issued the publication, "Exemption of Oil and Gas Exploration and Production Wastes from Federal Hazardous Waste Regulations"[13]. This document provided a clarification of the exemption of certain oil and gas E&P wastes from regulation as hazardous wastes under RCRA Subtitle C. The document included background on the E&P exemption, basic rules for determining the exempt or non-exempt status of wastes, examples of exempt and non-exempt wastes, the status of E&P waste mixtures, and clarifications of several misunderstandings about the exemption.

B. The State Review Process

As a critical part of EPA's 1988 regulatory determination to exempt oil and gas wastes from the Subtitle C provisions of RCRA EPA pledged to help states improve their regulatory programs. Subsequently, the Interstate Oil and Gas Compact Commission (IOGCC), which represents the governors of oil and gas producing states, formed the Council on Regulatory Needs and received a grant from EPA to identify the elements of effective state regulatory programs. The Council was created in 1989 as a forum where state oil and gas and environmental regulators, environmental groups, and industry representatives could work together to achieve this goal. After eighteen months, the Council produced a Guidelines document, which was published in 1990. These Guidelines were updated and expanded in 1994. The Guidelines were used as the basis for reviewing state programs by multi-stakeholder review teams. The purpose of the state review program is to provide an ongoing assessment of the effectiveness of state E&P waste regulatory programs in protecting the environment.

C. The State Review Process Becomes "STRONGER"

Incorporated as a non-profit corporation in June 1999, *State Review of Oil and Natural Gas Environmental Regulations* (STRONGER) became the independent stakeholder governing body that manages the state review process. Its Board of Directors consists of three state regulators, three environmental/ public interest representatives and three industry representatives. The EPA, DOE, and Department of the Interior participate as non-voting Board members. The IOGCC also participates through its State Review Committee, which provides for liaison with the states, provides three state regulators to serve on the Board, and provides state regulators to participate in periodic updates to the Guidelines. In 2000 and again in 2005, STRONGER updated and expanded the Guidelines to remain current with emerging environmental concerns and regulatory program developments. The current subject areas of the Guidelines include General/ Administrative, Technical, Abandoned Sites, Naturally Occurring Radioactive Materials (NORM), and Stormwater Management. Following development of the 2000 guidelines revisions; STRONGER added rules of participation, designed to govern the selection of participating states, preparation for reviews, conduct of reviews report writing, and dispute resolution.

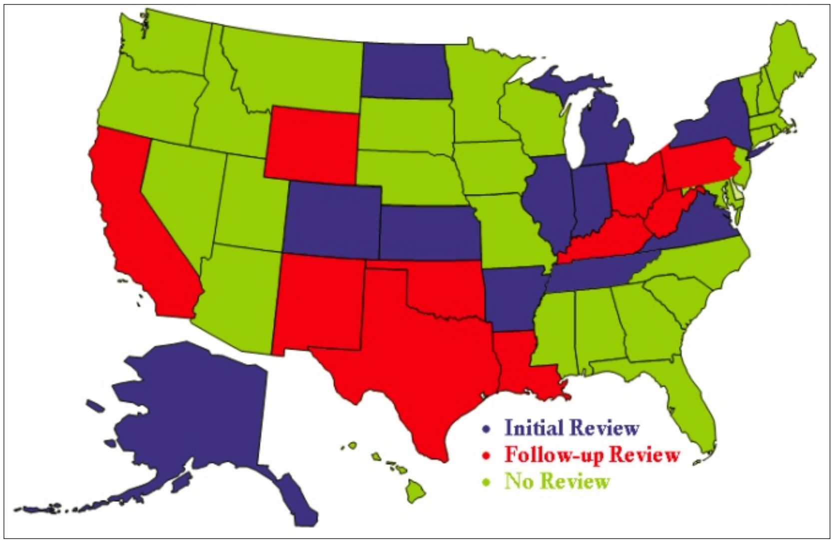


Figure 11 Map of states that have been reviewed through the state review process

D. State Review Accomplishments

Figure 11 is a map of the states that have undergone initial and follow-up state reviews. Individual state reviews are available on the internet at www.strongerinc.org

Figure 12 shows that as of 2008, reviews had been conducted at least once in states that represent just over eighty-nine percent of 2007 U.S. oil and gas production. This means that states that have not had at least an initial review accounted for less than 143 million barrels of oil production out of the nearly 1.38 billion barrels produced in 2007.

Determining the effectiveness of state oil and gas environmental programs in managing E&P wastes is a primary goal of the STRONGER state review process.

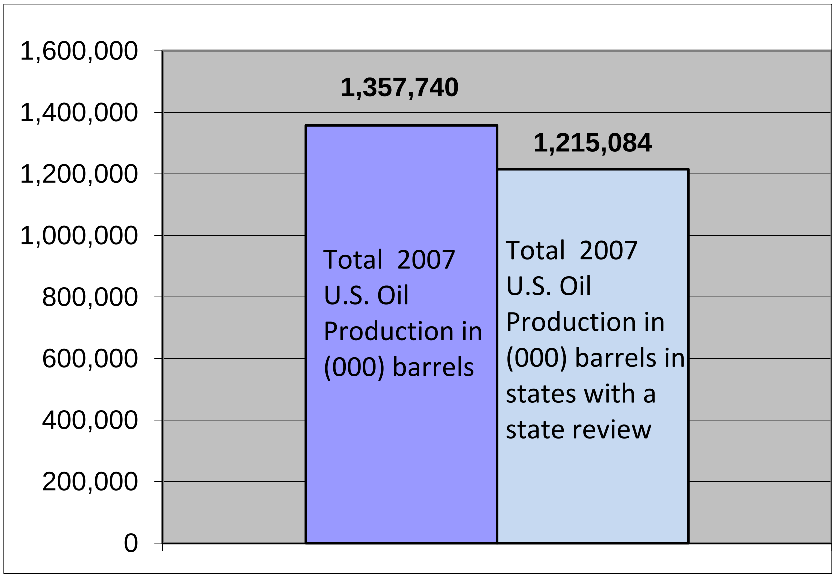


Figure 12 Total U.S. Oil production vs. production in reviewed states

Follow-up reviews have shown this effectiveness by revealing that about 75% of the recommendations made during initial state reviews had been addressed by the time a follow-up review was conducted (See figure 13).

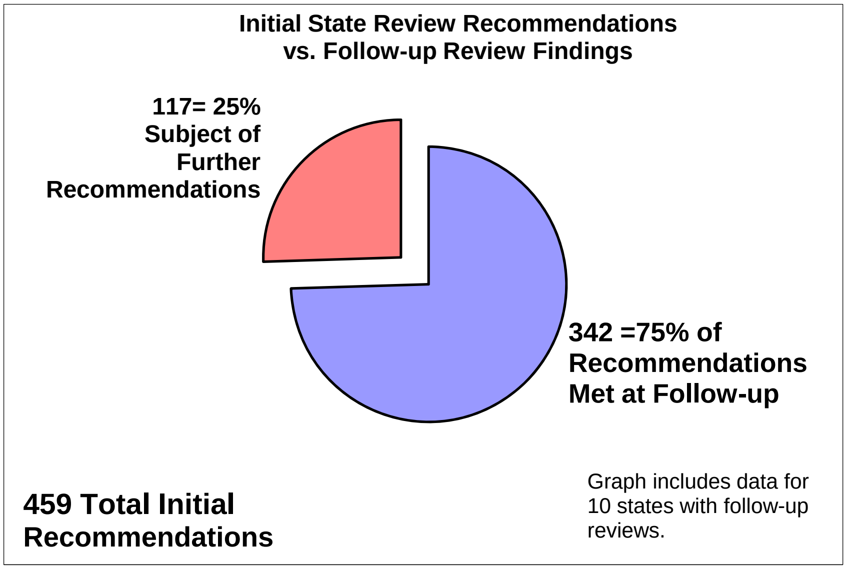


Figure 13 Percentage of recommendations met at follow-up review

This also demonstrates that state programs are dedicated to upgrading their environmental programs when needed to insure that E&P waste management is handled effectively.

In addition to individual state reviews, STRONGER is currently updating a 1998 summary of effectiveness of the state review process that will document the changes that have been made to regulatory programs in response to the findings and recommendation of initial and follow-up state reviews.

7. Data Management

Although the requirements for data management and handling are typically specified in state administrative laws & regulations rather than specific oil and gas regulations, the importance of managing regulatory data cannot be overstated. Information lies at the heart of regulatory implementation. The regulatory agency's ability to extract, analyze and accurately present data is essential to the protection of water resources.

Only by sharing and validating data across agency jurisdictions, with regulatory field staff, regulated industries, and the public, can decision-makers accurately assess trends in energy production, water quality and supply, and maintain the delicate balance between competing natural resources such as petroleum and water. However, the disturbing fact is that nationwide, much environmental compliance monitoring data is not yet in electronic format. Even in agencies where automated data systems exist, vast filing systems of wholly paper-bound archives provide the only access to important legacy background data. Obstacles to converting these archives to electronic databases include lack of funding and overstretched personnel resources.

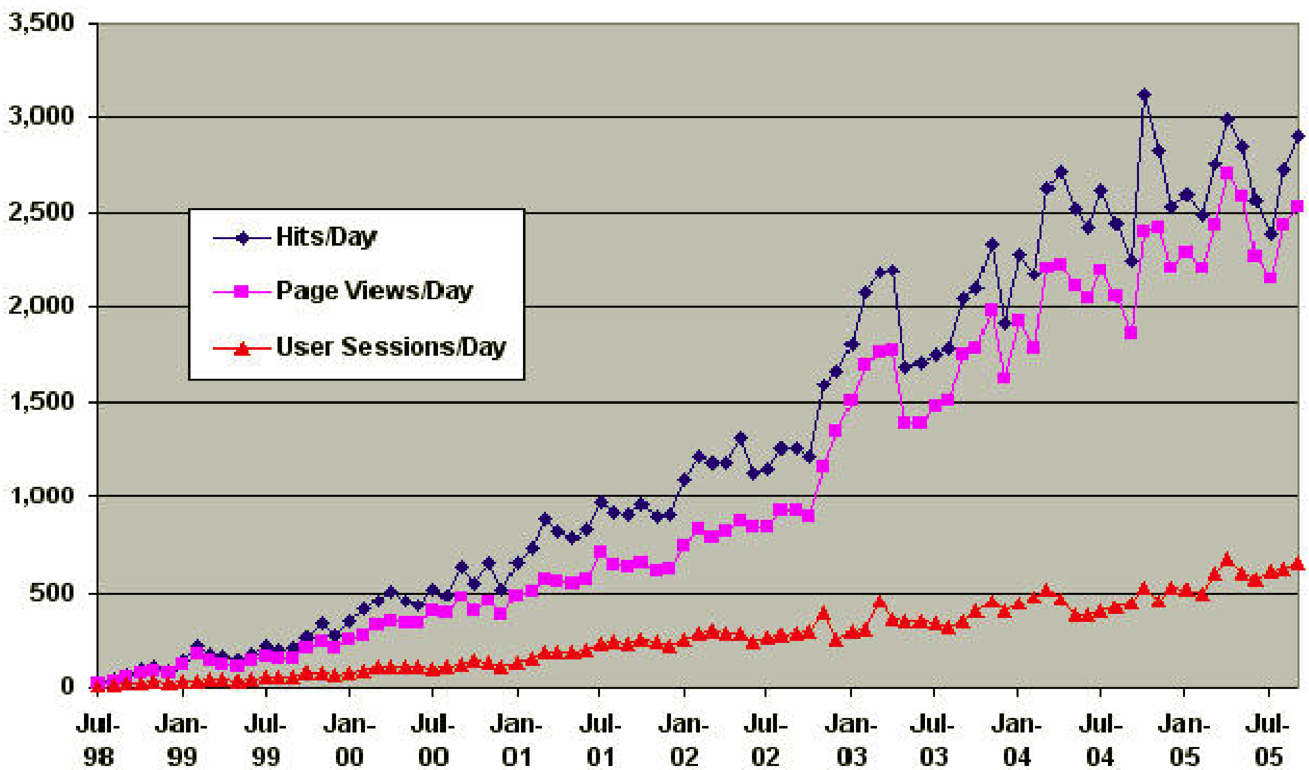


Figure 14 Increase in web traffic from July 1998 to July 2005 at the New York Department of Environmental Conservation

Managing natural resources wisely demands easy access to such caches of stored data for trend analyses and interpretation of the environmental effects of fossil fuel and mineral extraction operations on water quantity and quality. Even in agencies that do manage large amounts of data through client-server database applications, the extensive variability in the development tools used to create these systems and the differences in their form and function have created many technical obstacles in sharing data between the agencies and with the public. Overcoming the barriers created by early software programming and hardware choices has been difficult, with the result that large quantities of data have historically been accessible by only a few people. The increasing use of the internet, however, points to the future of database development and implementation.

As Figure 14 shows, state agencies like the New York Department of Environmental Conservation have seen substantial increases in public use of their websites over the past decade.

Regardless of the methods used for accessing data, the problems involved in developing functional data management tools are best solved at the state agency level because national databases cannot meet day-to-day state regulatory needs. The principal reasons for this are that national databases:

- are not always readily accessible to state agencies and the public;
- do not contain all of the information needed to regulate at the state level;
- are designed to contain and convey a national picture and thus cannot meet the needs of individual state programs.

Throughout the years of evolving technology from paper-based forms submittal and manual processing to electronic submittal, scanning, processing, and publication of technical data to the Web, the states have been developing, continually improving, and incrementally rolling out oil and gas regulatory data bases such as GWPC's Risk Based Data Management System (RBDMS). Though sometimes difficult, this is being slowly accomplished within the constraints of agency workloads and program funding.

Databases like RBDMS have been enhanced many times to include new features, such as modules for managing oil and gas production data and for tracking multilateral well construction details, downhole locations, inspection reports and other monitoring data.

Although technology advances in the last decade have cleared some of the hurdles to data usage and exchange of data between disparate databases and agency jurisdictions, there are still unfulfilled needs including:

- thorough conversion of paper archives to electronic databases in state agencies throughout the nation;
- continued development of web interfaces to improve access to information and to provide gateways for data exchange where information is kept in proprietary databases;
- broad application of Geographic Information Systems (GIS) technology to present data in a visual format;
- widespread use of monitoring data which exists in data systems that span jurisdictional boundaries such as state oil and gas and water quality agencies, USGS, EPA, and USDA
- widespread integration of oil and gas data with water quality, injection and other environmental data streams

8. Key Messages and Suggested Actions

The key messages and suggested actions shown below are based on an analysis of the requirements specified in state oil and gas regulations.

Key Message 1: Claims that the oil and gas E&P industry in the U.S. is unregulated are not supported by the findings of this report. We believe enactment of national regulations on oil and gas exploration and production would be costly to the states, duplicative of state regulation, and ultimately ineffective because such regulations would be too far removed from field operations. Current state regulation of oil and gas activities is environmentally proactive and preventive. All oil and gas producing states have regulations which are designed to provide protection for water resources such as those governing the authorization for drilling, completion, operation and closure of wells. Most state oil and gas agencies also have requirements on the management of fluid handling facilities and spills.

The content and specificity of regulation varies somewhat from state to state. While some states may have detailed regulations in an area such as pits, another state may have more generalized requirements. The reasons for these variations are related to factors such as geography, geology, climate, publicly perceived needs, and age, amount and type of production. For example, states with a principal focus on non coalbed methane gas production may have fewer regulations governing pits unrelated to drilling. This would be expected since; in general, conventional gas production tends to result in smaller amounts of co-produced water than coalbed methane production. Consequently, there is less need for complex or detailed pit construction requirements for pits unrelated to drilling. It should be noted that recent development in shale gas reservoirs throughout the U.S. has resulted in the use of formation treatment practices such as fracturing that are now returning large amounts of fluids to the surface. Consequently, regulations in some states with this recent activity may not yet reflect this with respect to surface storage and management of treatment fluids.

It is very important to note that many of the items listed in the Suggested Action 1 are already properly addressed in a number of state oil and gas regulatory programs. Therefore, the inclusion of an item on the following list of suggested actions is not intended to show that a particular program or specific state lacks the authority or capability to protect water resources through the application of its existing regulations. The purpose of the list is to provide states with an evaluation tool which may be used to assess current regulations and determine if a need exists for updates or revisions.

Suggested Action 1: While current state oil and gas regulations provide multiple mechanisms to protect water resources, there may be regulatory areas which could be reviewed and upgraded if needed including:

- ❖ Casing and cement: The following specifications should be considered:
    - o Construction materials and methods meeting a specific industry standard such as the API RP-65;
    - o Surface casing set to a sufficient depth below the deepest ground water or USDW; whichever is more appropriate in a given state;
    - o Cement circulated to the surface on the outside of surface casing or cement circulated on the intermediate or production casing string into at least the next larger cemented casing string (e.g. from production casing to intermediate casing or intermediate casing into surface casing etc…);

- Production casing required and set with an amount of cement sufficient to prevent the upward migration of fluids under all reservoir conditions;
- Centralizers used at appropriate intervals to assure that a cement sheath surrounds the casing strings;
- Prior notice of casing and cementing operations to regulatory agencies to provide them with an opportunity to witness well construction and, in the absence of witnessing, the submittal of appropriate proof of proper casing and cementing records

❖ Temporary Abandonment (TA): For wells that are placed on TA status in locations where bottom hole pressure is sufficient to raise fluid levels to a height which could intersect a ground water zone or USDW, or in fields where enhanced recovery is being used, the following requirements should be considered:

- casing integrity demonstrations; including the placement of bridge plugs, when necessary, to prevent ground water contamination; or
- assurance that static fluid levels in the well are below ground water zones

❖ Plugging: Materials and methods used in plugging should be limited to those that, through an appropriate verification or certification process, are deemed effective in maintaining the long term ability of a well or wellbore to prevent the upward migration of fluids. The use of non standard plugging materials and methods such as "brush plugs", "bentonite clay" and "bullhead plugging" should be carefully assessed before being allowed. Unless a bridge plug is used as the base for plugging or a well is plugged from the bottom of the hole, the tagging of plugs should be considered to demonstrate that unsupported cement plugs remain where they were placed.

❖ Tanks: Tank materials and construction methods should meet an appropriate industry or technical standard and tanks should be maintained in a manner that prevents leakage. In the absence of an adopted industry standard, the materials required in tank construction should be suitable for their usage as determined by the appropriate state agency. For example, the use of tanks that are made of non corrosion resistant steel should not be used for the storage of produced water since many oil and gas brines are corrosive in nature. The use of well constructed containment dikes surrounding tank batteries, where needed to prevent water contamination, should be considered. Further, containment dikes should meet a permeability standard, as demonstrated by testing methods such as a percolation rate test, or a holding time standard. There should be a requirement that areas inside the dike be kept free of fluids unless a release from a tank has occurred or after rainfall events so they will serve the purpose for which they were constructed. Regulations should specify how long releases or other fluids inside a containment dike should be allowed to remain before removal.

❖ Pits: Pits used for long term storage of produced fluids or other RCRA exempt waste should be required to utilize a natural or artificial liner, where needed to protect ground water. Liners should meet specific permeability and construction standards designed to prevent downward migration of fluids into ground water. Pits should not be excavated to a depth that exceeds the seasonal high water table or used in areas where the underlying bedrock contains seepage routes, solution features or springs. Pits used for long term storage of produced fluids or other RCRA exempt waste should not be allowed within the boundaries of a designated 100 year flood event without implementation of construction requirements designed to prevent ingress and egress of fluids during a flood. Pits designated as evaporation pits should not be allowed in regions where average annual precipitation exceeds average annual evaporation and all evaporation pits should be lined as noted above to prevent downward migration of fluids. States should consider prohibiting the use of pits within the boundaries of public water supply and wellhead protection areas. Pit closure specifications including the disposition of fluids and solids in the pit and the disposal of pit liners should be implemented.

- ❖ Spill Remediation: Operators should be required to remediate soils affected by oil and saltwater spills to a specific cleanup standard such as a Total Petroleum Hydrocarbon (TPH) level for oil affected soil and a Sodium Absorption Ratio (SAR) for salt affected soil. The table used by Colorado; shown at the end of Chapter 5, provides an example of the type of cleanup standard that can be applied by a regulatory agency.

- ❖ Surface Discharge: The discharge of drilling or RCRA exempt E&P waste fluids at the surface should not occur without the issuance of a state NPDES permit if the discharge could enter water, or similar permit or an authorization administered by the oil and gas agency if the discharge could not enter water.

Key Message 2: Historically, some E&P activities have caused contamination of both surface and ground water. Past practices related to pit construction, well cementing and operation, and well plugging were not always adequate to prevent migration of contaminants to surface and ground water. However, the development and application of new regulations over the past twenty to twenty-five years has provided a more effective means for protecting water resources from various oil and gas E&P activities.

For example, the implementation of requirements for pit liners in many states has resulted in increased protection of shallow ground water by preventing leaching of contaminants into the subsurface. Similarly, upgraded requirements for surface casing and cement have created better protection for ground water formations from the intrusion of fluids from deeper zones and from well completion and treatment operations. In fact, based on over sixty years of practical application and a lack of evidence to the contrary, there is nothing to indicate that when coupled with appropriate well construction; the practice of hydraulic fracturing in deep formations endangers ground water. There is also a lack of demonstrated evidence that hydraulic fracturing conducted in many shallower formations presents a substantial risk of endangerment to ground water.

Suggested Action 2a: Comprehensive studies should be undertaken to determine the relative risk to water resources from the practice of shallow hydraulic fracturing. The studies should focus on evaluating both the theoretical and empirical relationship of hydraulic fracturing to ground water protection. In conjunction with the knowledge of current practices, these studies should be used to develop a generic set of BMPs for the practice of hydraulic fracturing from which state agencies may as appropriate:

- ❖ develop their own state specific BMPs;

- ❖ develop additional state regulations relative to the practice

Suggested Action 2b: State and federal agencies should remain cautious about developing and implementing regulations based on anecdotal evidence alone. Nevertheless, complaints of ground water contamination attributed to hydraulic fracturing should continue to be investigated by the appropriate state agency to determine whether or not ground water has been affected and whether a causal relationship can be established between any impacts to ground water and the implementation of hydraulic fracturing.

Within this context, states should consider requiring companies to submit a list of additives used in formation fracturing and their concentration within the fracture fluid matrix. Further, states that do not currently regulate handling and disposal of fracture fluid additives and constituents recovered during recycling operations should consider the need to develop such regulations.

Suggested Action 2c: When a formation to be fractured is in close proximity to a USDW, as determined by the regulatory agency using state and site specific criteria, an appropriate cement evaluation tool such as, at a minimum, a cement bond log coupled with a variable density log (CBL/ VDL, See Attachments 5 and 6) should be run on the well before hydraulic fracturing occurs. These logs should be interpreted by a qualified person in the regulatory agency to determine if adequate cement to casing and cement to formation bond exists over a sufficient wellbore interval to prevent the upward migration of fluids within the casing/ formation annulus. In cases where the bond is questionable, remedial cementing followed by re-verification of cement quality should be conducted prior to conducting hydraulic fracturing.

Suggested Action 2d: Hydraulic fracturing in oil or gas bearing zones that occur in non-exempt USDW's should be either stopped, or restricted to the use of materials that do not pose a risk of endangering ground water and do not have the potential to cause human health effects (e.g. fresh water, sand etc...)

Key Message 3: Many states split jurisdiction between oil and gas and water quality or pollution control agencies over some aspects of oil and gas regulation including tanks, pits, waste handling and spills. Some oil and gas programs reside within an agency that also houses other state environmental programs. However, most are separate entities that may not have regulatory systems which are formally coordinated. The lack or formal coordination between state agencies can sometimes result in a case of jurisdictional confusion under which the management of environmental issues could be delayed.

Suggested Action 3: Where split jurisdiction of oil and gas operations exists, formal memorandums of agreement and regulatory implementation plans should be negotiated between state agencies with jurisdiction over parts of oil and gas operations so that coordination of effort can be achieved. Regular review and updating of these documents should also be undertaken to reflect jurisdictional changes and newly identified coordination issues.

Key Message 4: The state review process managed by STRONGER, Inc. is an effective tool for ensuring that state environmental regulatory programs related to the management of E&P waste are conducted in a manner that is protective of the environment. The success of the STRONGER process in promoting changes to state programs through its reviews and recommendations has resulted in an overall net increase in environmental protection for water resources and demonstrated that state regulation is a very effective means of managing E&P wastes.

Suggested Action 4a: The RCRA Subtitle C exemption for E&P wastes should be retained and E&P waste regulation should continue to be managed primarily at the state level.

Suggested Action 4b: STRONGER should continue its efforts to obtain volunteer states for initial review, conduct follow-up reviews to evaluate state response to initial review recommendations and revise its guidelines, as necessary, to stay current with respect to regulatory and technological advances.

Suggested Action 4c: STRONGER should evaluate whether to update its mission to include environmental elements of state oil and gas programs beyond the traditional area of E&P waste.

Key Message 5: The implementation and advancement of data management systems provides regulatory agencies with increasing capacity to track compliance, facilitate field inspections, and prepare reports that can be used to evaluate the effectiveness of state oil and gas regulations implementation. The exponential growth in data management capabilities, systems functionality and ease of use and access over the past several years has enhanced the ability of state agencies to more effectively manage the information they receive. However, there is still a need to convert paper records to electronic formats and to more fully integrate environmental data in a form that is accessible and easily understood.

Suggested Action 5: State oil and gas and other water protection agencies should continue to expand their data management capabilities and, within the confines of available funding, implement the latest technologies for electronically acquiring, storing, sharing, extracting and utilizing environmental data. The federal government should provide financial support to the state agencies efforts to hasten the pace of systems implementation and resulting data availability.

About the Authors

Michael Nickolaus has almost thirty years of geologic experience in coal and oil and gas development and regulation. Prior to joining the GWPC Mr. Nickolaus worked for the Indiana Department of Natural Resources, Division of Oil and Gas for nearly twenty years in permitting, enforcement and underground injection control. During his last two years with the division he served as the state Oil and Gas Director. He is the author of the Division of Oil and Gas, Spill Management Guide and subsequent interagency MOA regarding spill jurisdiction. He has authored numerous regulations and co-authored the state request to USEPA for primary enforcement authority of the Class II Underground Injection Control program. In 2000 he was the principal developer and co-author of the Division of Oil and Gas, Virtual Procedure Manual; which is still used by the division to implement the state oil and gas regulatory program. A 1979 graduate of Indiana University, he holds a BA in Geology. Mr. Nickolaus has been the Special Projects Director of the GWPC for four years. Mr. Nickolaus is a licensed Professional Geologist, and a member of the Society of Petroleum Engineers and the Association of Environmental & Engineering Geologists.

William Bryson has more than fifty years of experience in oil and gas exploration, production and regulation. He served as the Director of Oil and Gas for the State of Kansas Corporation Commission for over seven years, and Director of the Bureau of Oil Field and Environmental Geology for the Department of Health and Environment for eight years. He is a Past President of the GWPC. Mr. Bryson played an instrumental role in the initial development of the Underground Injection Control program in the 1970's and was one of three state members of the USEPA workgroup that formed the Regulatory Determination for the RCRA petroleum Exemption in 1988. He also chaired the Technical Group that developed the original Exploration and Production Waste Guidelines. A 1958 graduate of Kansas State University, he holds both a BS and MS in Geology. Mr. Bryson is a Professional Geologist.

Paul Jehn has over twenty-five years of experience in environmental assessment, policy development, evaluation and remediation. Prior to joining the GWPC, Mr. Jehn was a consultant for Argonne National Laboratory and the Associate Director of the Water Resources Research Institute at the University of Idaho. He spent five years as the Chief, Bureau of Monitoring and Technical Support for the Idaho Department of Health and Welfare, Division of Environmental Quality. He has co-authored more than thirty technical and professional publications dealing with ground water and surface water He received a BS in Geology from the University of Dayton in 1971, an MS in Geochemistry from Northeast Louisiana University in 1979 and has completed course work for a Ph.D. in Geochemistry through Texas Tech University. He is the Technical Director of the GWPC and is responsible for management of state implementation and advancement of the Risk Based Data Management System. This system is used by twenty-three states to store and utilize electronic data related to underground injection control wells and oil and gas wells

List of Acronyms and Terms

Acronym/ Term	Meaning
ANSI	American National Standards Institute
API	American Petroleum Institute
ASTM	American Society for Testing and Materials
BHP	Bottom Hole Pressure
CBM	Coalbed Methane (Also known as Coalbed Natural Gas)
CBL	Cement Bond Log
Cement	A mixture of cement and water with no aggregates included. Commonly referred to as “Portland” or “neat” cement
CIBP	Cast Iron Bridge Plug
DOE	United States Department of Energy
E&P	Exploration and Production
EPA	United States Environmental Protection Agency
Gas	Means natural gas consisting of “hydrocarbons which at atmospheric conditions of temperature and pressure are in a gaseous phase”[22]
Ground water	Water contained in geologic media which has been designated by a state as usable for domestic, industrial or municipal purposes
GWPC	Ground Water Protection Council
Hydraulic Barrier	A natural or artificial barrier through which the flow of fluid is substantially inhibited
Hydraulic Fracturing	The practice of pumping fluids under pressure into a rock formation for the purpose of causing fracturing of the rock matrix to create preferential flow pathways.
IOGCC	Interstate Oil and Gas Compact Commission
NETL	National Energy Technology Laboratory
NPDES	National Pollutant Discharge Elimination System
OGAP	Oil and Gas Accountability Project
Permeability	A measure of the resistance offered by rock to the movement of fluids through it.[22] (Note: As used in this report, the term also applies to non rock materials such as soil, clay etc…)
Plugging	The process of sealing a well with cement and other materials as a means of permanent closure
RCRA	The Resource Conservation Recovery Act of 1976 and amendments
SDWA	The Safe Drinking Water Act of 1974 and amendments
STRONGER	State Review of Oil and Natural Gas Environmental Regulation
TA	Temporary abandonment of a well
TDS	Total Dissolved Solids (Typically reported in Mg/L or Parts Per Million (PPM))
TPH	Total Petroleum Hydrocarbons (Typically reported as a % by volume or in Parts Per Million)
UIC	The Underground Injection Control program authorized by the SDWA
UL	Underwriters Laboratory
USDW	Underground Source of Drinking Water as defined in 40 CFR Part 144.3
VDL	Variable Density Log

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Attachments

Attachment 1

Survey of State CBM Hydraulic Fracturing Practices, February 2008
(Selection of states based on the DOE Map of Major and Minor Coal Producing States 12/31/2000)

	Question: Is diesel used as a fracture fluid additive for CBM zones that are also USDW's?			
State	**Person Contacted**	**Date**	**Yes/ No**	**Additional Notes**
Alabama	Dave Bolin, Alabama State Oil and Gas Board	12/13/2007	No	
Alaska	Jim Regg , Alaska Oil and Gas Conservation Commission	12/19/2007	No	
Arizona	Steve Rauzi, Arizona Geological Survey	2/11/2008	No	(No CBM production)
Arkansas	Larry Bengal, Arkansas Oil and Gas Commission	2/12/2008	No	
Colorado	Tricia Beaver, Colorado Oil & Gas Conservation Commission	12/14/2007	No	
Illinois	Doug Shutt, Illinois Division of Oil and Gas	2/8/2008	No	
Indiana	Mona Nemecek, Indiana Division of Oil and Gas	2/7/2008	No	
Kansas	Alan Snider, Kansas Corporation Commission	12/14/2007	No	(No USDW CBM zones)
Kentucky	Marvin Combs, Kentucky Division of Oil and Gas	2/8/2008	No	(No CBM production)
Louisiana	Jim Welsh, Louisiana Office of Conservation	2/11/2008	No	(No USDW CBM zones)
Maryland	Ed Larrimore, Maryland Department of Environment	2/11/2008	No	(No CBM production)
Mississippi	Lisa Ivshin, Mississippi Oil and Gas Board	2/11/2008	No	(No CBM Production)
Montana	Tom Richmond, Montana Board of Oil & Gas Conservation	12/13/2007	No	
New Mexico	Mark Fesmire, New Mexico Oil Conservation Division	2/7/2008	No	
North Dakota	Mark Bohrer, North Dakota Oil and Gas Commission	2/7/2008	No	(No CBM production)
Ohio	Scott Kell, Ohio Department of Natural Resources	12/13/2007	No	
Oklahoma	Lori Wrotenbery, Oklahoma Corporation Commission	12/26/2007	No	(No USDW CBM zones)
Pennsylvania	Dave English, Pennsylvania Department of Environmental Protection	12/14/2007	No	
Tennessee	Mike Burton, Tennessee Oil and Gas Board	2/8/2008	No	(No CBM production)
Texas	Leslie Savage, Texas Railroad Commission	2/12/2008	No	
Utah	John Baza, Utah Department of Natural Resources	12/13/2007	No	
Virginia	Bob Wilson, Virginia division of Gas and Oil	12/14/2007	No	(No USDW CBM zones)
Washington	Ron Teissere, Washington Department of Natural Resources	2/11/2008	No	
West Virginia	James Martin, West Virginia Department of Environmental Protection	12/14/2007	No	
Wyoming	Janie Nelson, Wyoming Oil & Gas Conservation Commission	12/19/2007	No	

Attachment 2

Oil and Gas Production by State for 2007

State	Oil Production (000) bbls.	Gas Production (Mmcf)
Alabama	7,173.00	289,618
Alaska	263,595.00	3,479,290
Arizona	43.00	655
Arkansas	6,031.00	177,160
California	216,778.00	339,389
Colorado	23,237.00	1,254,529
Florida	2,078.00	2,000
Illinois	9,609.00	169
Indiana	1,727.00	3,606
Kansas	36,490.00	366,859
Kentucky	2,666.00	95,437
Louisiana	76,651.00	1,381,033
Maryland	0.00	35
Michigan	5,201.00	270,571
Mississippi	20,396.00	272,878
Missouri	80.00	0
Montana	34,829.00	120,575
Nebraska	2,334.00	1,560
Nevada	408.00	5
New Mexico	58,831.00	1,555,618
New York	380.00	54,942
North Dakota	45,058.00	70,797
Ohio	5,455.00	88,095
Oklahoma	60,952.00	1,744,393
Oregon	0.00	409
Pennsylvania	3,653.00	182,277
South Dakota	1,665.00	11,880
Tennessee	284.00	3,942
Texas	396,894.00	6,929,402
Utah	19,520.00	356,038
Virginia	18.00	112,057
West Virginia	1,574.00	231,184
Wyoming	54,130.00	2,111,766

Source: U.S. Energy Information Administration

Attachment 3

List of Crosswalk Review Areas of State Oil and Gas Regulations Related to Water Protection

Item
1 General Authority
1A Oil and gas agency shares regulatory authority with other state/ federal agencies for
1A1 Spills of RCRA exempt waste (E&P waste exempt under Subtitle C)
1A2 Surface discharge of RCRA exempt waste
1A3 Land application of RCRA exempt waste
1A4 On-site burial of RCRA exempt waste
1A5 Other aspects of oilfield regulation (Please specify)
1B Oil and gas agency has written MOA's/ MOU's with other state/ federal agencies
1C Wells/sites undergo inspection based on complaints (Please detail process)
2 Permitting
2A Types of permits/ prior authorizations required
2A1 Drilling, redrilling, workover, conversion etc…
2A2 Plugging
2A3 Treatment, Stimulation or Fracturing
2A4 Land application of exempt waste
2A5 Storm water (e.g. wellsite construction)
2A6 Surface discharge of fluids
2B Permits require review by a geologist or engineer (Specify which)
2C Public notice required prior to issuance
2D Permits can be denied or delayed if applicant is not in compliance
2E Permits can be revoked for non compliance
2F Permit applications reviewed by other state agencies
3 Formation Treatment, Stimulation or Fracturing
3A Specific regulations governing practice
3B Prior authorization required
3C Public notice required
3D Specific requirements
3D1 Specific materials/ chemicals prohibited (e.g. diesel fuel, 2-BE, etc…)
3D2 Agency may require submission of specific information about constituents

3D3 Inspector witnessing required
3D4 Pressure limitations specified
3D5 Minimum Depth Required
3D6 Adjacent water well testing and monitoring required
3E Reporting required
3E1 Materials
3E2 Volumes
3E3 Chemicals
3E4 Pressures
3E5 Depths
3F Does the state conduct ground water contamination investigations as a result of complaints
3G In conducting ground water investigations has your agency found any cases during the past 5 years where:
3G1 Constituents from treatment, stimulation or fracturing have entered a fresh water zone (Specify the number of cases)
3G2 The process of treatment, stimulation or fracturing has resulted in impacts to fresh water zones (Specify the number of cases)
4 Well Construction (New wells)
4A Surface casing below all fresh water zones required
4A1 Cementation from bottom to top required
4A2 Cementation from bottom through all fresh water zones required
4A3 Cementation from bottom to specific distance above bottom
4B Intermediate casing required
4B1 Cementation from bottom to top required
4B2 Cementation from bottom to next cemented string required
4B3 Cementation from bottom to specific distance above bottom
4C Long string casing required
4C1 Cementation from bottom to top required
4C2 Cementation from bottom to next cemented string required
4C3 Cementation from bottom to specific distance above bottom
4F Casing must meet API standards
4G Casing pressure test required
4H Cement must meet API standards
4I Cement evaluation logs required
4K Cement testing required
4L Cement set-up period required before resuming drilling
4M Inspection/ witnessing of well casing and cementing specified

5 Temporary Abandonment
5A Temporary abandonment allowed
5B Prior authorization required
5C Renewal allowed
5D Duration of TA/ Shut-in status limited
5E Well integrity demonstration or specific construction required
6 Well Plugging
6A Cementing or removal of uncemented casing required
6B Cement must meet API standards
6C Materials other than cement allowed (e.g. bentonite) Note: Except for spacers
6D Cement placement above producing zones required
6E Cement placement across deepest fresh water zones required
6F Bridge plugs required
6G Plugging plan submission prior to plugging required
6H Notice of intent to plug required
6I Witnessing of plugging by agency personnel specified
6J Cement tickets allowed in lieu of witnessing
6K Plug tagging/ placement verification required
6M Cement plug strength specified
6N Plugging method specified
6N1 Pump and plug required
6N2 Dump bailing allowed
6O Reporting required
6O1 Cement type (e.g. Class A)
6O2 Cement volume (e.g. Sacks or Cu. Ft.)
6O3 Bridge plugs (e.g. CIBP, Cement Retainer etc…)
6O4 Casing left
6O5 Plug placement intervals
6P State run orphan well program
6P1 Orphan well program funding primarily from dedicated funds
6P2 Orphan well program funding primarily from general funds
6P3 Number of orphan wells in program
6P4 Number of orphan wells plugged during past 5 years

8 Tanks
8A Prior authorization required
8B Inspection before use required
8C Construction standards
8C1 Tank materials specified
8C2 ASTM, ANSI, API or other technical specifications required
8D Siting requirements
8D1 Distance from surface water specified
8D2 Depth to ground water considered
8D3 Prohibited in flood plains, wetlands or other surface water areas
8E Secondary containment required
8E1 Capacity specified
8E2 Permeability specified
8E3 Maintenance required
8E4 Standing fluids in containment area prohibited
8E5 Surface discharge of waste fluids in containment area regulated
7 Pits
7A Drilling/ workover
7B Salt water storage
7C Waste storage
7D Emergency
7E Burn Off
7F Temporary oil storage
7G Prior authorization required
7H Prior surface owner notification required
7I Inspection before use required
7J Construction requirements
7J1 General
7J2 Specific
7J3 Liners required
7J3A Natural allowed
7J3B Artificial required
7J3B1 Competency standards specified
7J3B2 Seaming standards specified

7J3B3 Bed preparation standards specified
7J4 Freeboard required
7J5 Siting requirements
7J5A Distance from surface water specified
7J5B Prohibited in water table
7M Duration of use regulated
7N Closure requirements
7N1 Prior authorization required
7N2 Prior notice to surface owner required
7N3 Soil sampling required
7N4 Closure report required
9 Exempt Waste Handling
9A On site- disposal of waste regulated
9B Application of salt water to roads/ lands regulated
9C Application of tank bottoms and waste oil to roads/ lands regulated
9D Chain of custody for off site disposal required
10 Spills
10A Agency notification of spills required (Within what time period?)
10B Landowner notification of spills required (Within what time period?)
10B On-site remediation regulated
10C Cleanup standards specified

Attachment 4

Text of the Memorandum of Agreement between USEPA and BJ Services Company, Halliburton Energy Services, Inc. and Schlumberger Technology Corporation

Authors Note: Although reformatted from the original file for this report, the attachment contains the unabridged text of the agreement minus the actual signature pages of the parties.

A MEMORANDUM OF AGREEMENT Between THE UNITED STATES ENVIRONMENTAL PROTECTION AGENCY And BJ Services Company, Halliburton Energy Services, Inc., and Schlumberger Technology Corporation

Elimination of Diesel Fuel in Hydraulic Fracturing Fluids Injected into Underground Sources of Drinking Water During Hydraulic Fracturing of Coalbed Methane Wells

12 December, 2003

I. PREAMBLE

A. This is a voluntary agreement between the United States Environmental Protection Agency (EPA) and BJ Services Company, Halliburton Energy Services, Inc., and Schlumberger Technology Corporation (the service companies are collectively referred to as the "Companies;" individually as "Company"), by which the Companies agree to eliminate diesel fuel in hydraulic fracturing fluids injected into coalbed methane (CBM) production wells in underground sources of drinking water (USDWs) and, if necessary, select replacements that will not cause hydraulic fracturing fluids to endanger USDWs. While the Companies do not necessarily agree that hydraulic fracturing fluids using diesel fuel endanger USDWs when they are injected into CBM production wells, the Companies are prepared to enter into this agreement in response to EPA's concerns and to reduce potential risks to the environment.

B. Hydraulic fracturing is a technique used by the oil and gas industry to improve the production efficiency of production wells, including CBM production wells. A hydraulically-created fracture acts as a conduit in the rock or coal formation that allows the oil or gas to travel more freely from the rock pores. To create such a fracture, a viscous, water-based fluid is sometimes pumped into the coal seam under high pressures until a fracture is created. These fluids consist primarily of water, but in some cases they also contain various additives. Diesel fuel has been used as an additive in hydraulic fracturing fluids for the purpose of enhancing proppant delivery.

C. The Companies and EPA recognize that the primary purpose of this agreement is to eliminate the use of diesel fuel in hydraulic fracturing fluids injected into CBM production wells in USDWs.

II COMMON AGREEMENTS AND PRINCIPLES

A. The Companies and EPA acknowledge that only technically feasible and cost effective actions to provide alternatives for diesel fuel will be sought. The determination of what is technically feasible and cost-effective will vary and it is at the discretion of each Company to make that determination.

B. The Companies and EPA will exercise good faith in fulfilling the obligations of this Memorandum of Agreement (MOA).

C. Nothing in this agreement constrains EPA or the Companies from taking actions relating to hydraulic fracturing that are authorized or required by law. Nothing in this agreement should be understood as an EPA determination that use by the Companies of any particular replacement for diesel fuel is authorized under the Safe Drinking Water Act (SDWA) or EPA's Underground Injection Control (UIC) Regulations, or that the elimination of diesel fuel or use of any replacement fluid constitutes or confers any immunity or defense in an action to enforce the SDWA or EPA's UIC regulations. Nothing in this Agreement shall, in any way, be considered a waiver of the Companies' right to challenge any subsequent regulations or limitations on the use of hydraulic fracturing or its components by any state or Federal agencies.

D. All commitments made by EPA in this MOA are subject to the availability of appropriated funds and Agency budget priorities. Nothing in this MOA, in and of itself, obligates EPA to expend appropriations or to enter into any contract, assistance agreement, interagency agreement, or other financial obligations. Any endeavor involving reimbursement or contribution of funds between EPA and the Companies will be handled in accordance with applicable laws, regulations, and procedures, and will be subject to separate agreements that will be effected in writing by representatives of the Companies and EPA, as appropriate.

E. EPA and the Companies will bear their own costs of carrying out this agreement. The Companies agree that activities undertaken in connection with this MOA are not intended to provide services to the Federal government, and they agree not to make a claim for compensation for services performed for activities undertaken in furtherance of this MOA to EPA or any other Federal agency.

F. Any promotional material that any Company develops may advise the public of the existence of this MOA and its terms, but must not imply that EPA endorses the purchase or sale of products and services provided by any Company

G. This MOA does not create any right or benefit, substantive or procedural, enforceable by law or equity against the Companies or EPA, their officers or employees, or any other person. Nothing herein shall be deemed to create any requirement under any existing law or regulation**.** This MOA does not direct or apply to any person outside the Companies and EPA.

III. EPA ACTIONS

A. To the extent consistent with Agency authorities and policies governing recognition awards, EPA agrees to consider providing the Companies with recognition for their achievements in replacing diesel fuel in fracturing fluids injected into USDWs for CBM production and for their public service in protecting the environment. In addition, EPA agrees to provide appropriate information to the public, other Federal agencies and Congress, regarding actions taken by the Companies under this MOA. EPA agrees to obtain the Companies' approval on any specific language intended for public distribution that discusses the Companies' participation in this MOA and agrees to notify the Companies sufficiently in advance of EPA's intention to publicly use the Companies' name or release information, including press releases, concerning the Companies' participation in this MOA.

B. EPA agrees to contact appropriate individuals representing states, industry, and the Department of Energy to inform them of progress in implementing the MOA and to solicit their cooperation, as appropriate, in implementation of the MOA.

C**.** EPA agrees to issue a final version of the draft report entitled *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs* as soon as reasonably possible.

D. The parties agree that nothing in this MOA is intended to affect, in any way, the existing criteria and process for identifying exempted aquifers under 40 C.F.R. Parts 144 and 146.

E. EPA agrees to consider other measures as appropriate to aid implementation of the MOA, including measures to facilitate efforts undertaken by the Companies pursuant to this MOA.

IV. THE COMPANIES' ACTIONS

A. The Companies agree to eliminate diesel fuel in hydraulic fracturing fluids injected into CBM production wells in USDWs within 30 days of signing this agreement. If necessary, the Companies may use replacement components for hydraulic fracturing fluids that will not endanger USDWs.

B. The Companies agree to notify the Assistant Administrator for EPA's Office of Water within 30 days after any decision to re-institute the use of diesel fuel additives in hydraulic fracturing fluids injected into USDWs for CBM production.

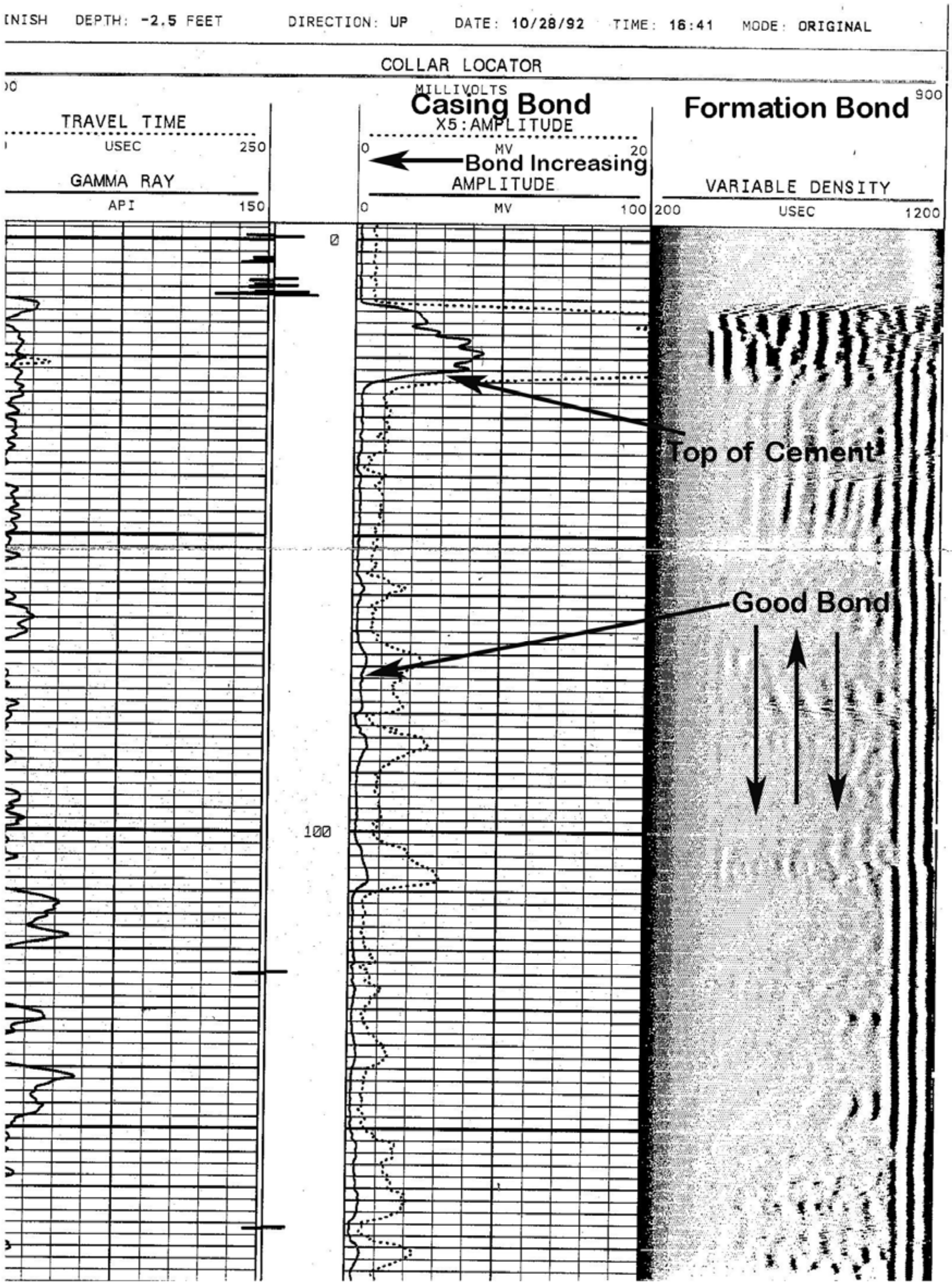
C. The Companies and EPA may, upon unanimous consent of the signatories, include additional provisions in, or make modifications to, this MOA. Such additions or modifications must contribute to the goal of preventing the endangerment of USDWs. Nothing herein shall be construed as requiring the adoption of any such additional provisions or modifications.

V. DISPUTE RESOLUTION AND TERMINATION OF AGREEMENT

A. Any Company or EPA may terminate its participation in this MOA by providing written notice to the other signatories. Such termination as to that Company (or, if EPA terminates the MOA, as to all) will be effective 30 days after the receipt of written notice and will result in no penalties or continuing obligations by the terminating Company (or, if EPA terminates the MOA, any signatory). If EPA or any Company terminates the MOA, EPA and/or that Company will refrain from representing that the Company is continuing to cooperate with EPA on replacing diesel fuel in hydraulic fracturing fluids injected in USDWs for CBM production, provided that they may continue to make reference to activities undertaken through the date of this termination. If its participation in this MOA is terminated by any Company, the MOA shall have no further force and effect for the terminating Company, and the terminating Company shall have no further obligation under the MOA.

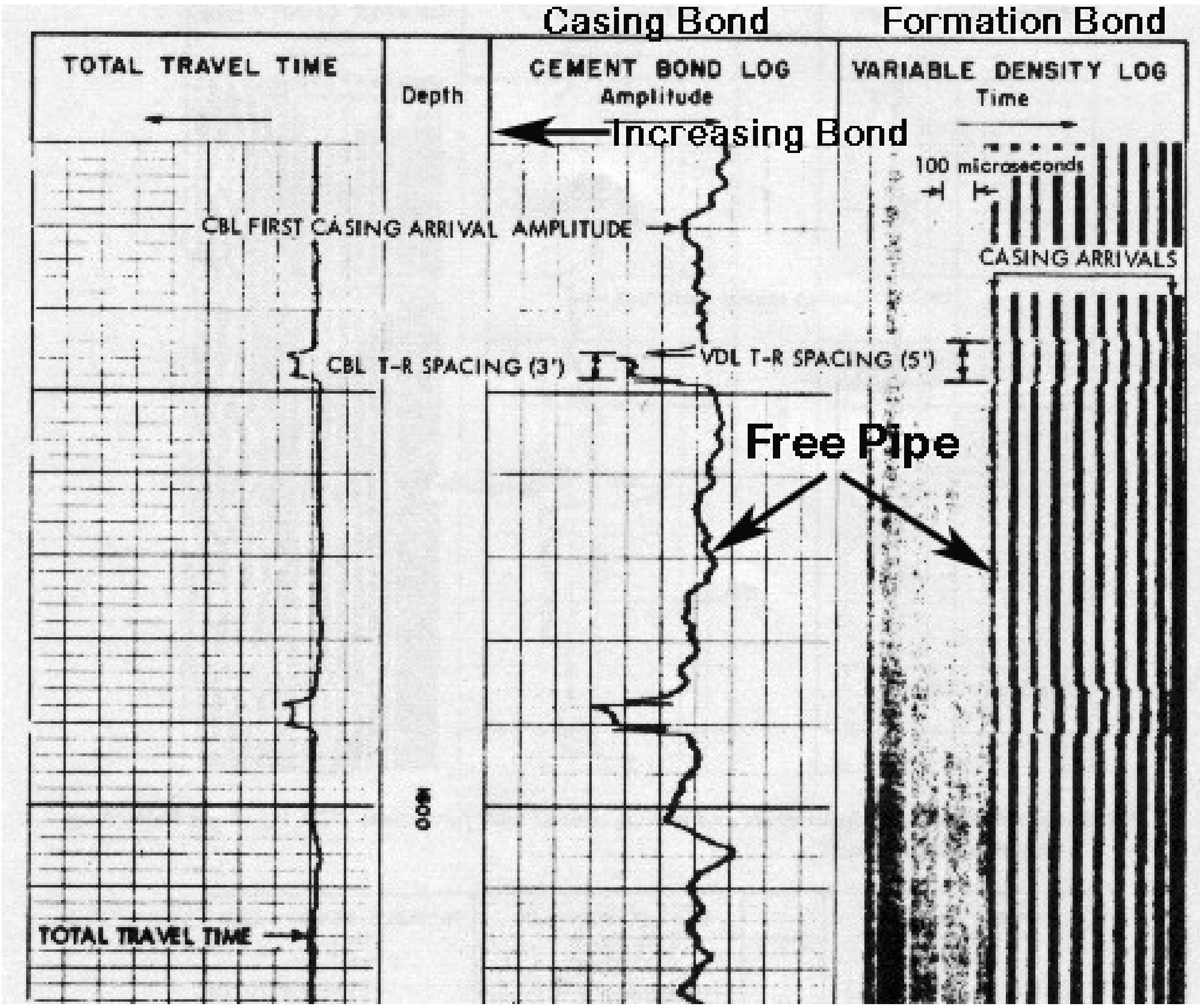
Attachment 5

Example of Cement Bond Log/ Variable Density Log Showing Good Cement Bond



Attachment 6

Example of Cement Bond Log/ Variable Density Log Showing No Cement Bond/ Free Pipe



Attachment 7

MEMORANDUM OF AGREEMENT
BETWEEN THE
INDIANA DEPARTMENT OF NATURAL RESOURCES
AND THE
INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

Purpose and Intent

1) This Memorandum of Agreement (MOA) establishes policies, responsibilities, and procedures pursuant to statutes and rules with respect to a regulatory program regarding notification for and cleanup of spills related to petroleum exploration and production activities.

2) This agreement is entered into by the Indiana Department of Natural Resources and signed by the Director of the Department of Natural Resources (Director) with the Indiana Department of Environmental Management and signed by the Commissioner of the Department of Environmental Management (Commissioner).

3) This agreement shall become effective when approved by the Director and Commissioner.

Agency Authorities

4) The Indiana Department of Natural Resources, Division of Oil and Gas (Division) has authority over spills of crude oil, crude oil tank bottoms and saltwater related to petroleum exploration and production activities. The Indiana Department of Environmental Management (IDEM) Office of Environmental Response is responsible for and has authority over spills of any substance into the environment.

5) Nothing in this agreement is intended to affect any programs related to the environment that are not directly under the authority of the Division.

Agency Responsibilities

6) The Division shall respond to all spills of oil and saltwater from the operation and maintenance of tanks, pipes, pumps, valves, and wells related to oil and gas exploration and production and shall have responsibility for spills that meet the following criteria:

- Spills contained within the boundaries of an approved secondary containment structure regardless of volume; or

- Spills not contained within the secondary containment structure if the spill volume is less than 1000 gallons and does not threaten to enter ditches, creeks, ponds or other waters of the state
- Spills of oil when less than 55 gallons leave the facility boundary.

7) The IDEM shall be responsible for spills of oil and saltwater from the operation and maintenance of tanks, pipes, pumps, valves, and wells related to oil and gas exploration and production that meet the following criteria:

- Spills not contained within the secondary containment structure if the spill volume is greater than 1000 gallons; or
- Spills that enter or threaten to enter ditches, creeks, ponds, or other waters of the state regardless of volume.
- Spills of oil when greater than 55 gallons leave the facility boundary
- Spills when threats to public health are actual or imminent.
- Spills that are not contained and free material not removed within the time specified in the working agreement.

1) The Indiana Department of Environmental Management is also responsible for any spills not specifically covered by the program to be implemented under the terms of this MOA.

2) The Division shall implement a program related to spills of crude oil, crude oil tank bottoms, and saltwater resulting from petroleum exploration and production that requires an owner or operator to contain, remediate, reuse, remove and treat, or dispose of spills and spill contaminated materials in accordance with promulgated rules, policies, and best management practices.

3) The Division shall promulgate rules that are based on a review of similar regulatory programs in other oil and gas producing states. These rules shall include provisions concerning spill containment, cleanup standards, bioremediation, excavation and disposal, and site remediation.

4) The agency deemed to have responsibility for a spill shall be the lead agency. The lead agency shall provide the on scene coordinator and shall be responsible for the notification and coordination of all state and local agencies involved in the spill.

Communication

5) The parties agree to maintain a level of cooperation and coordination to assure the successful and effective administration of a spill notification and cleanup program. This shall include appropriate and timely contact between the Division and the IDEM. To

facilitate this line of communication the Division and the IDEM shall develop a system for reporting, evaluating, and responding to spills.

6) The IDEM is responsible for keeping the IDNR apprised of the meaning and content of statutes, rules, technical standards, policy decisions, directives, and any other factors which may affect this agreement or the program. The IDNR shall promptly inform IDEM of any resource allocation changes such as budget or equipment, any proposed, pending, or enacted modifications to statutes, rules or guidelines, and any judicial decisions or administrative actions which the IDNR believes might affect the Divisions ability to administer the program.

7) The strategies and priorities for implementation of the program shall be established by this agreement. If requested by either party, meetings will be scheduled at reasonable intervals between the Division and the IDEM to review specific operating procedures, resolve problems, or discuss mutual concerns involving the administration of the program.

1) Disputes arising out of the implementation of this agreement shall be resolved through negotiation between the Division and the IDEM. The process of dispute resolution shall be initiated via referral from the Division Inspector and ERS Responder to the next higher level of authority within their respective agencies. The Director of the Division of Oil and Gas and the Emergency Response Branch Chief of the IDEM shall be the final authorities for dispute resolution.

Conformance with Laws and Rules

2) The Division and IDEM shall administer a spill notification and remediation program consistent with the intent of IC 14, IC 13, promulgated rules, this MOA, and any separate working agreements which may be entered into between the Director or his/her designee (IDNR) and the Commissioner and his/her designee (IDEM) as necessary for the full administration of the program. This program shall also specifically conform to the intent of 327 IAC 2-6.1.

Duration of MOA

3) This agreement will remain in effect until such time as either of the parties determines that the program implemented under this agreement is no longer functioning in the manner intended, is not operating in the best interests of the citizens of Indiana, is not protective of the environment, or is no longer authorized or funded.

Enforcement

4) When this agreement has been fully implemented the IDEM will consult with the Division before taking enforcement actions related to spills that are deemed the responsibility of the Division under this agreement. Every effort shall be made to obtain consensus between the agencies with respect to enforcement actions. This paragraph is intended to provide for timely, coordinated, and non duplicative enforcement.

Review and Modifications

5) This agreement and any working agreements shall be reviewed annually by the Indiana Department of Environmental Management and the Division to determine its adequacy and legality. This agreement may be modified upon the initiative of either agency. Modifications must be in writing and must be signed by the Director and Commissioner. Modifications become effective when signed by both the Director and Commissioner. Modifications may be made by revision prior to the effective date of this agreement or subsequently by addenda attached to this agreement and consecutively numbered, signed and dated.

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